YEAR ENDING 2005

ANNUAL REPORT
OF

Montana Dakota Utilities

GAS UTILITY

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

2005 Gas Annual Report

Instructions

General

1. A Microsoft EXCEL workbook of the annual report is being provided on computer disk for your convenience. The workbook contains the schedules of the annual report. Each schedule is on the worksheet named that schedule. For example, Schedule 1 is on the sheet titled "Schedule 1". By entering your company name in the cell named "Company" of the first worksheet, the spreadsheet will put your company name on all the worksheets in the workbook. The same is true for inputting the year of the report in the cell named "YEAR". You can "GOTO" the proper cell by using the F5 key and selecting the name of the cell. 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 2005 report form. It has been updated and slightly changed from the 2004 report.

2. Use of the disk is optional. The disk and the report cover shall be returned when the report is filed.

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

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

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

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

7. The information required with respect to any statement shall be furnished as a minimum requirement to which shall be added such further information as is necessary to make the required schedules not misleading.

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

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

Schedule 14

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

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

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

Schedule 15

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

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

Schedule 16

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

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

Schedule 17

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

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

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

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

Schedule 24

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

Schedule 26

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

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

Schedule 27

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

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

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

Schedule 28

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

Schedule 31

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

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

Schedule 34

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

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

Schedule 36a

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

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

Gas Annual Report

Table of Contents

continued on next page

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 1**

IDENTIFICATION

Year: 2005

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:	Donald R. Ball
5a.	Telephone Number:	(701) 222-7630

Control Over Respondent

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

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

   1b. Means by which control was held:

   1c. Percent Ownership:

SCHEDULE 2

Line No.	**Board of Directors 1/** Name of Director and Address (City, State) (a)	Remuneration (b)
1	Martin A. White, Bismarck, ND	-
2	Terry D. Hildestad, Bismarck, ND 2/	-
3	Warren L. Robinson, Bismarck, ND 3/	-
4	Paul K. Sandness, Bismarck, ND	-
5	Bruce T. Imsdahl, Bismarck, ND	-
6		-
7		
8		
9	1/ Montana-Dakota Utilities Co. is a division of MDU Resources Group, Inc.,	
10	and has no Board of Directors. The affairs of the Company are managed by	
11	a Managing Committee, the members of which are provided herein rather	
12	than the directors of MDU Resources Group, Inc.	
13	2/ Terry D. Hildestad became a member of the Managing Committee effective	
14	May 1, 2005.	
15	3/ Warren L. Robinson retired on 1/03/06.	
16		
17		
18		

Officers

Year: 2005

Line No.	Title of Officer (a)	Department Supervised (b)	Name (c)
1	President and Chief	Executive	Bruce T. Imsdahl
2	Executive Officer		
3			
4	Executive Vice President	Business Development and	Dennis L. Haider
5		Gas Supply	
6			
7	Executive Vice President -	Accounting, Information Systems,	John F. Renner
8	Finance & Chief Accounting	Regulatory Affairs and Fleet	
9	Officer	and Procurement	
10			
11	Vice President	Regulatory Affairs	Donald R. Ball
12			
13	Vice President	Operations	David L. Goodin
14			
15	Vice President	Human Resources	Richard D. Spratt
16			
17	Vice President	Electric Supply	Andrea L. Stomberg
18			
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CORPORATE STRUCTURE

Year: 2005

Line	Subsidiary/Company Name	Line of Business	Earnings (000's)	Percent of Total
1	Montana-Dakota Utilities Co./	Electric and Natural Gas	$17,455	6.36%
2	Great Plains Natural Gas Co.	Distribution		
3	(Divisions of MDU Resources			
4	Group, Inc.)			
5				
6	WBI Holdings, Inc.	Pipeline and Energy Services and	163,717	59.66%
7		Natural Gas and Oil Production		
8				
9	Knife River Corporation	Construction Materials and	55,040	20.06%
10		Mining		
11				
12	MDU Construction Services	Construction Services	14,558	5.31%
13	Group, Inc.			
14				
15	Centennial Energy Resources LLC	Independent Power Production	22,921	8.35%
16				
17	Centennial Holdings Capital Corp.	Other	707	0.26%
50	**TOTAL**		$274,398	100.00%

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 5

CORPORATE ALLOCATIONS - GAS

Year: 2005

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Audit Costs	Administrative & General	Various Corporate Overhead Allocation Factors	$2,907	2.23%	$127,325
2						
3	Advertising	Administrative & General	Various Corporate Overhead Allocation Factors,	2,434	2.23%	106,911
4			and/or Actual Costs Incurred			
5						
6	Air Service	Administrative & General	Various Corporate Overhead Allocation Factors, Time	2,738	1.68%	159,808
7			Studies, and/or Actual Costs Incurred			
8						
9	Automobile	Administrative & General	Various Corporate Overhead Allocation Factors, Time	841	2.39%	34,325
10			Studies, and/or Actual Costs Incurred			
11						
12	Bank Services	Administrative & General	Various Corporate Overhead Allocation Factors and/or	9,781	2.23%	428,410
13			Actual Costs Incurred			
14						
15	Corporate Aircraft	Administrative & General	Various Corporate Overhead Allocation Factors, Time	3,736	2.25%	162,341
16			Studies, and/or Actual Costs Incurred			
17						
18	Consultant Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or	55,377	3.16%	1,696,141
19			Actual Costs Incurred			
20						
21	Contract Services	Administrative & General	Various Corporate Overhead Allocation Factors and/or	34,248	2.14%	1,569,862
22			Actual Costs Incurred			
23						
24	Directors Expenses	Administrative & General	Corporate Overhead Allocation Factor Based on a	46,766	2.24%	2,037,414
25			Combination of Net Plant Investment and Number of			
26			Employees			
27						
28	Employee Benefits	Administrative & General	Corporate Overhead Allocation Factor Based on	5,312	2.23%	233,161
29			Number of Employees			

CORPORATE ALLOCATIONS - GAS

Year: 2005

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Employee Meetings	Administrative & General	Various Corporate Overhead Allocation Factors and/or	3,553	2.25%	154,639
2			Actual Costs Incurred			
3						
4	Employee Reimbursable	Administrative & General	Various Corporate Overhead Allocation Factors, Time	5,243	2.01%	256,039
5	Expenses		Studies, and/or Actual Costs Incurred			
6						
7	Legal Retainers & Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or	22,851	2.24%	999,467
8			Actual Costs Incurred			
9						
10	Meal Allowance	Administrative & General	Various Corporate Overhead Allocation Factors, Time	94	2.53%	3,625
11			Studies, and/or Actual Costs Incurred			
12						
13	Meals & Entertainment	Administrative & General	Various Corporate Overhead Allocation Factors, Time	2,355	1.96%	117,900
14			Studies, and/or Actual Costs Incurred			
15						
16	Moving Expense	Administrative & General	Various Corporate Overhead Allocation Factors, Time	4,038	2.23%	176,882
17			Studies, and/or Actual Costs Incurred			
18						
19	Industry Dues & Licenses	Administrative & General	Various Corporate Overhead Allocation Factors, Time	3,033	2.43%	121,951
20			Studies, and/or Actual Costs Incurred			
21						
22	Office Expenses	Administrative & General	Various Corporate Overhead Allocation Factors and/or	3,301	2.25%	143,234
23			Actual Costs Incurred			
24						
25	Prepaid Insurance	Administrative & General	Various Corporate Overhead Allocation Factors and	42,217	2.17%	1,905,752
26			Allocation Factors Based on Actual Experience			

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 5

CORPORATE ALLOCATIONS - GAS

Year: 2005

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Permits and Filing Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or			
2			Actual Costs Incurred	476	2.23%	20,837
3						
4	Postage	Administrative & General	Various Corporate Overhead Allocation Factors and/or			
5			Actual Costs Incurred	674	2.23%	29,583
6						
7	Payroll	Administrative & General	Various Corporate Overhead Allocation Factors, Time			
8			Studies, and/or Actual Costs Incurred	437,308	2.13%	20,054,768
9						
10	Rental	Administrative & General	Various Corporate Overhead Allocation Factors and/or			
11			Actual Costs Incurred	231	4.18%	5,294
12						
13	Supplemental Insurance	Administrative & General	Various Corporate Overhead Allocation Factors			
14				52,178	2.33%	2,182,945
15	Reference Materials	Administrative & General	Various Corporate Overhead Allocation Factors and/or			
16			Actual Costs Incurred	3,055	2.21%	135,198
17						
18	Seminars & Meeting	Administrative & General	Various Corporate Overhead Allocation Factors, Time			
19	Registrations		Studies, and/or Actual Costs Incurred	3,393	2.12%	156,286
20						
21	Software Maintenance	Administrative & General	Various Corporate Overhead Allocation Factors, Time			
22			Studies, and/or Actual Costs Incurred	4,718	2.23%	206,638
23						
24	Training Material	Administrative & General	Various Corporate Overhead Allocation Factors, Time			
25			Studies, and/or Actual Costs Incurred	3,795	2.22%	167,328
26						
27	**TOTAL**			$756,653	2.22%	$33,394,064

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2005

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**KNIFE RIVER CORPORATION**	Expense	Actual Costs Incurred			
2		Materials		$1,042		$492
3		Contract Services		0		
4		Office Supplies		1,295		332
5		Computer Services		54		14
6		Miscellaneous		688		176
7						
8		Capital	Actual Costs Incurred			
9		Contract Services		4,266		
10		Materials		6,841		
11						
12						
13						
14						
15						
16						
17						
18						
19		Total Knife River Corporation Operating Revenues for the Year 2005			1,604,610,000	
20		Excludes Intersegment Eliminations				
21						
22						
23	**TOTAL**	**Grand Total Affiliate Transactions**		$14,186	0.0009%	$1,014

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2005

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**WBI HOLDINGS, INC**	Natural Gas	Actual Costs Incurred			
2		Purchases/Transportation		$59,550,290		$17,427,436
3						
4						
5						
6		Expense	Actual Costs Incurred			
7		Contract Services		1,632		781
8		Legal Fees		59,347		15,227
9		Materials		919		0
10		Consulting		9,318		2,391
11		Office Supplies		44		11
12		Software Maintenance		4,626		1,311
13		Miscellaneous		141		0
14		Reimbursable Expense		1,103		315
15						
16		Capital	Actual Costs Incurred			
17		Contract Services		55,695		
18		Miscellaneous		11,966		
19		Reimbursable Expense		335		
20		Material		6,020		
21						
22		Other Transactions/Reimbursements	Actual Costs Incurred			
23		Miscellaneous		1,383		355
24						
25						
26						
27		Total WBI Operating Revenues for the Year 2005			$919,661,000	
28		Excludes Intersegment Eliminations				
29						
30						
31	**TOTAL**	**Grand Total Affiliate Transactions**		$59,702,819	6.4918%	$17,447,827

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2005

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**	Capital	Actual Costs Incurred			
2	**SERVICES GROUP, INC**	Materials		$6,070		
3						
4						
5						
6						
7						
8						
9		Other Transactions/Reimbursements	Actual Costs Incurred			
10		Miscellaneous		281		72
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25		Total MDU Construction Services Group, Inc Operating Revenues for the Year 2005			$687,125,000	
26		Excludes Intersegment Eliminations				
27						
28						
29	**TOTAL**	**Grand Total Affiliate Transactions**		$6,351	0.0009%	$72

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2005

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**CENTENNIAL ENERGY**	Expense	* Various Corporate Overhead			
2	**RESOURCES/CHCC**	Corporate Aircraft	Allocation Factors and/or	$164,690		$42,302
3		Rent	Actual Costs Incurred	83,217		21,352
4		Cost of Service		104,780		26,884
5		Strategic Planning		281		72
6						
7		Capital				
8		Corporate Aircraft	Actual Costs Incurred	24		
9		Subcontract Labor		946,057		
10						
11						
12						
13						
14						
15						
16						
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18						
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20						
21						
22		Total Centennial Energy Resources/CHCC Operating Revenues for the Year 2005			$54,546,000	
23		Excludes Intersegment Eliminations				
24						
25						
26						
27						
28						
29	**TOTAL**	**Grand Total Affiliate Transactions**		$1,299,048	2.3816%	$90,610

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 200

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	KNIFE RIVER CORPORATION	MDU RESOURCES GROUP, INC.				
2		Corporate Overhead	* Various Corporate Overhead Allocation			
3		Audit Costs	Factors, Time Studies and/or Actual	$58,995		
4		Advertising	Costs Incurred	49,271		
5		Air Service		68,304		
6		Automobile		10,597		
7		Bank Services		198,501		
8		Corporate Aircraft		67,508		
9		Consultant Fees		688,032		
10		Contract Services		702,119		
11		Directors Expenses		940,233		
12		Employee Benefits		108,052		
13		Employee Meeting		71,548		
14		Employee Reimbursable Expense		114,192		
15		Express Mail		61		
16		Insurance		758,247		
17		Legal Retainers & Fees		462,898		
18		Moving Allowance		81,960		
19		Meal Allowance		1,555		
20		Cash Donations		20,272		
21		Meal & Entertainment		45,447		
22		Industry Dues & Licenses		50,337		
23		Office Expenses		65,998		
24		Supplemental Insurance		1,012,510		
25		Permits & Filing Fees		9,655		
26		Postage		13,592		
27		Payroll		7,538,605		
28		Reference Materials		61,888		
29		Rental		1,305		
30		Seminars & Meeting Registrations		68,971		
31		Software Maintenance		95,744		
32		Training		77,659		
33		**Total MDU Resources Group, Inc.**		$13,444,056	0.8967%	

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2005

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	KNIFE RIVER CORPORATION	MONTANA-DAKOTA UTILITIES CO.				
2		Communications Department	* Various Corporate Overhead Allocation			
3		Automobile	Factors, Cost of Service Factors, Time	$617		
4		Air Service	Studies and /or Actual Costs Incurred	52		
5		Contract Services		520		
6		Employee Reimbursable Expense		143		
7		Materials		328		
8		Meals & Entertainment		4		
9		Office Expenses		1,156		
10		Office Telephones		151,670		
11		Organizational Dues		7		
12		Payroll		71,699		
13		Permits & Filing Fees		310		
14						
15						
16		Office Services	* General Office Complex and Office			
17		Automobile	Supplies Cost of Service Allocation	45		
18		Contract Services	Factors	1,133		
19		Employee Meetings		33		
20		Express Mail		15,031		
21		Rental of Office Equipment		373		
22		Office Expenses		13,212		
23		Postage		11,850		
24		Cost of Service - General Office Buildings		474,782		111,828
25						
26						
27		Information Systems	* Various Corporate Overhead Allocation			
28		Automobile	Factors and /or Actual Costs Incurred	66		
29		Air Service		76		
30		Contract Services		225		
31		Employee Reimbursable Expense		89		
32		Meals & Entertainment		19		
33		Office Expenses		3,625		
34						
35						

Company Name: Montana-Dakota Utilities Co.

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 200

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	KNIFE RIVER CORPORATION	Office Telephones		3,454		
2		Payroll		34,917		
3		Reference Materials		4		
4		Seminars & Meeting Registrations		369		
5						
6						
7		Other Miscellaneous Departments	* Various Corporate Overhead Allocation			
8		Automobile	Factors and /or Actual Costs Incurred	59		
9		Office Telephones		101		
10		Payroll		(3,017)		
11						
12						
13						
14		Other Direct Charges	Actual Costs Incurred			
15		Employee Discounts		49,561		7,614
16		Corporate/Commercial Air Service		50,899		
17		Computer/Software Support		883,112		
18		Electric Consumption		43,272		
19		Gas Consumption		107,486		90,088
20		Deferred Compensation		570,896		
21		Miscellaneous		150,623		
22						
23						
24		**Total Montana-Dakota Utilities Co.**		$ 2,638,803	0.1760%	$209,529

Company Name: Montana-Dakota Utilities Co.

SCHEDULE

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 200

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	KNIFE RIVER CORPORATION	OTHER TRANSACTIONS/REIMBURSEMENTS				
2						
3		Insurance		20,471		
4		Federal & State Tax Liability Payments		42,189,042		
5		KESOP carrying costs		336,103		
6		Tax Deferred Savings Plan		99,148		
7		Interest		(112,640)		
8		Miscellaneous Reimbursements		(1,127,424)		
9						
10		**Total Other Transactions/Reimbursements**		$41,404,701	2.7616%	
11						
12		**Grand Total Affiliate Transactions**		$57,487,560	3.8343%	$209,529
13						
14						
15						
16		**Total Knife River Corporation Operating Expenses for 2005 - Excludes Intersegment Eliminations**			$1,499,291,000	

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

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2005

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	MDU RESOURCES GROUP, INC.				
2		Corporate Overhead	* Various Corporate Overhead Allocation			
3		Audit Costs	Factors, Time Studies and/or Actual	$30,735		
4		Advertising	Costs Incurred	25,819		
5		Air Service		30,386		
6		Automobile		8,594		
7		Bank Services		103,413		
8		Corporate Aircraft		43,383		
9		Consultant Fees		421,786		
10		Contract Services		365,669		
11		Directors Expenses		494,224		
12		Employee Benefits		56,157		
13		Employee Meeting		37,274		
14		Employee Reimbursable Expense		58,406		
15		Express Mail		39		
16		Insurance		560,722		
17		Legal Retainers & Fees		241,196		
18		Meal Allowance		870		
19		Cash Donations		10,561		
20		Meal & Entertainment		28,017		
21		Moving Expense		42,695		
22		Industry Dues & Licenses		29,699		
23		Office Expenses		34,415		
24		Supplemental Insurance		527,489		
25		Permits & Filing Fees		5,030		
26		Postage		7,102		
27		Payroll		6,383,498		
28		Reference Materials		32,466		
29		Rental		1,823		
30		Seminars & Meeting Registrations		36,304		
31		Software Maintenance		49,880		
32		Training Material		40,365		
33		**Total MDU Resources Group, Inc.**		$9,708,017	1.5007%	

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2005

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	MONTANA-DAKOTA UTILITIES CO.				
2		Communications Department	* Various Corporate Overhead Allocation			
3		Expense	Factors, Cost of Service Factors, Time			
4		Automobile	Studies and /or Actual Costs Incurred	$293		
5		Air Service		601		
6		Contract Services		251		
7		Employee Reimbursable Expense		987		
8		Materials		134		
8		Meals & Entertainment		322		
9		Office Expenses		590		
10		Office Telephone		64,659		
11		Payroll		35,760		
12		Permits & Filing Fees		161		
13		Professional Organ Dues		3		
14						
15		Office Services	* General Office Complex and Office			
16		Expense	Supplies cost of Service Allocation			
17		Automobile	Factors	45		
18		Contract Services		590		
19		Employee Meetings		33		
20		Express Mail		7,830		
21		Office Expenses		43,179		
22		Postage		6,174		
23		Cost of Service - General Office Buildings		380,862		$89,706
24						
25		Purchasing Department	* Various Corporate Overhead Allocation			
26		Capital	Factors, Cost of Service Factors, Time			
27		Payroll	Studies and /or Actual Costs Incurred	43,130		
28		Office Supplies		31		
29		Employee Reimbursable Expense		58		
30		Expense				
31		Office Telephones		52		
32						

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2005

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d)	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	Information Systems	* Various Corporate Overhead Allocation			
2		Expense	Factors and /or Actual Costs Incurred			
3		Automobile		37		
4		Contract Services		1,809		
5		Employee Reimbursable Expense		7		
6		Meals & Entertainment		0		
7		Office Expenses		29,011		
8		Office Telephones		1,790		
9		Payroll		12,491		
10		Seminars & Meeting Registrations		2		
11						
12		Region Operations	* Various Corporate Overhead Allocation			
13		Expense	Factors and /or Actual Costs Incurred			
14		Automobile		2,681		
15		Air Services		69		
16		Contract Services		845		
17		Custodial Services & Supplies		234		
18		Materials		907		
19		Meals & Entertainment		236		
20		Other Reimbruseable Expenses		506		
21		OfficeTelephone		16,180		
22		Payroll		12,411		
23		Photocopier		134		
24		Office Supplies		80		
25		Permits & Filing Fees		188		
26		Annual Easements		3,412		
27		Freight		19		
28		Utilities		1,506		
29		General & Administrative Expenses		304		
30						

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2005

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	Transportation Department	* Various Corporate Overhead Allocation			
2		Capital	Factors, Time Studies and /or Actual			
3		Payroll	Costs incurred	20,192		
4		Clearing Accounts				
5		Automobile		13		
6		Air Service		94		
7		Contract Services		160		
8		Corporate Aircraft		40		
9		Custodial Services		460		
10		Employee Reimbursable Expense		120		
11		Meals & Entertainment		33		
12		Office Expenses		32		
13		Office Telephone		531		
14		Professional Organ. Dues		22		
15		Payroll		12,605		
16		Permits & Filing Fees		3		
17		Seminars & Meeting Registrations		8		
18		Utilities		49		
19						
20		Other Miscellaneous Departments	* Various Corporate Overhead Allocation			
21		Expense	Factors, Time Studies and /or Actual			
22		Automobile	Costs incurred	34		
23		Payroll		(1,744)		
24						
25						

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2005

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	Capital				
2		Automobile		14		
3		Air Service		181		
4		Corporate Aircraft		118		
5		Professional Organ. Dues		30		
6		Employee Reimbursable Expense		302		
7		Meals & Entertainment		75		
8		Office Expenses		57		
9		Office Telephones		678		
10		Seminars & Meeting Registrations		20		
11						
12		Other Direct Charges	Actual Costs Incurred			
13		Utility/Merchandise Discounts		174,935		96,047
14		Corporate Aircraft		164,398		
15		Radio Maintenance		9,098		
16		Vehicle Maintenance		30,308		
17		Computer/Software Support		221,865		
18		Cathodic Protection		14,425		5,300
19		Purchased Power for Compressor Stations		69,476		61,782
20		Electric Compressor - Electricity Cost		107,330		28,478
21		Office Building Utilities		277,664		99,799
22		Miscellaneous		84,917		
23		BitterCreek Projects		1,075,907		
24						
25		Total Montana-Dakota Utilities Co. 1/		2,935,053	0.4537%	$381,112
26						
27		1/ Total Montana-Dakota Charges By Category				
28		Expense		2,855,998	0.4415%	
29		Capital		64,885	0.0100%	
30		Clearing		14,170	0.0022%	
31		Total		2,935,053	0.4537%	
32						

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2005

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	OTHER TRANSACTIONS/REIMBURSEMENTS				
2		Insurance	Actual Costs Incurred	$12,835		
3		Federal & State Tax Liability Payments		38,046,676		
4		Tax Deferred Savings Plan		12,733		
5		KESOP carrying costs		67,195		
6		Interest		(51,661)		
7		Miscellaneous Reimbursements		(23,189)		
8		**Total Other Transactions/Reimbursements**		$38,064,589	5.8841%	
9						
10		**Grand Total Affiliate Transactions**		$50,707,659	7.8385%	$381,112
11						
12						
13						
14		**Total WBI Holdings Operating Expenses for 2005 - Excludes Intersegment Eliminations**			$646,902,000	

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

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2005

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 Allocation			
3		Audit Costs	Factors, Time Studies and/or Actual	$8,595		
4		Advertising	Costs Incurred	7,178		
5		Air Service		18,903		
6		Automobile		1,836		
7		Bank Services		28,921		
8		Corporate Aircraft		10,002		
9		Consultant Fees		102,348		
10		Contract Services		102,292		
11		Directors Expenses		138,609		
12		Employee Benefits		15,804		
13		Employee Meeting		10,424		
14		Employee Reimbursable Expense		24,175		
15		Express Mail		9		
16		Insurance		131,877		
17		Legal Retainers & Fees		67,442		
18		Moving Allowance		11,941		
19		Meal Allowance		227		
20		Cash Donations		2,953		
21		Meal & Entertainment		8,094		
22		Industry Dues & Licenses		7,734		
23		Office Expenses		9,401		
24		Supplemental Insurance		147,518		
25		Permits & Filing Fees		1,407		
26		Postage		1,984		
27		Payroll		1,537,870		
28		Reference Materials		9,120		
29		Rent		186		
30		Seminars & Meeting Registrations		12,357		
31		Software Maintenance		13,949		
32		Training Material		11,344		
33		**Total MDU Resources Group, Inc.**		$2,444,500	0.3710%	

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2005

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 Allocation			
3		Air Service	Factors, Cost of Service Factors, Time	$7		
4		Automobile	Studies and /or Actual Costs Incurred	84		
5		Contract Services		72		
6		Professional Organ. Dues		1		
7		Office Expenses		166		
8		Office Telephone		19,034		
9		Payroll		9,713		
10		Employee Reimbursable Expense		18		
11		Materials		40		
12		Permits & Filing Fees		45		
13						
14		Office Services	* General Office Complex and Office			
15		Automobile	Supplies Cost of Service Allocation	7		
16		Contract Services		165		
17		Employee Meetings		9		
18		Express Mail		2,190		
19		Office Expenses		1,415		
20		Postage		1,726		
21		Cost of Service - General Office Buildings		246,475		$58,053
22						
23		Information Systems	* Various Corporate Overhead Allocation			
24		Contract Services	Factors and /or Actual Costs Incurred	53		
25		Employee Reimbursable Expense		5		
26		Office Expenses		853		
27		Payroll		15,463		
28		Office Telephones		501		
29						
30		Other Miscellaneous Departments	* Various Corporate Overhead Allocation			
31		Automobile	Factors, Time Studies and/or	10		
32		Office Telephones	Actual Costs Incurred	15		
33		Payroll		(407)		
34						

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2005

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	MDU CONSTRUCTION	Other Direct Charges	Actual Costs Incurred			
2	SERVICES GROUP INC	Legal Fees		5,019		
3		Contract Services		3,515		
4		Air Service		93,444		
5		Meals and Entertainment		4,897		
6		Employee Reimbursable Expense		9,148		
7		Advertising		31,974		
8		Telephone		5,898		
9		Consulting Service		43,912		
10		Computer/Software Support		1,194		
11		Office Expenses		5,966		
12		Filing fees		52,990		
13		Organizational Dues		285		
14		Reference Materials		1,706		
15		Training Material		4,637		
16		Miscellaneous		1,771		
17		Seminars and Meeting Registration		1,560		
18		Employee Discounts		3,365		
19		Gas Consumption		3,644		3,621
20		**Total Montana-Dakota Utilities Co.**		572,584	0.0869%	$61,675
21						
22		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual Costs Incurred			
23		Payroll		1,067,423		
24		Federal & State Tax Liability Payments		$14,185,549		
25		Audit fees		52,256		
26		Supplemental Insurance		38,716		
27		Insurance		7,726		
28		Miscellaneous		506,881		
29		KESOP/Deferred Comp carrying costs		2,995		
30						
31		**Total Other Transactions/Reimbursements**		15,861,545	2.4071%	
32						

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2005

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					
2	SERVICES GROUP INC					
3						
4						
5		**Grand Total Affiliate Transactions**		18,878,629	2.8649%	$61,675
6						
7		**Total MDU Construction Services Group, Inc. Operating Expenses for 2005**				
8		**Excludes Intersegment Eliminations**			$ 658,954,000	

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

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2005

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	CENTENNIAL ENERGY	MDU RESOURCES GROUP, INC.				
2	RESOURCES/CHCC	Corporate Overhead	* Various Corporate Overhead Allocation			
3		Audit Costs	Factors, Time Studies and/or Actual	$5,340		
4		Advertising	Costs Incurred	4,459		
5		Air Service		18,702		
6		Automobile		1,541		
7		Bank Services		17,966		
8		Corporate Aircraft		8,480		
9		Consultant Fees		64,049		
10		Contract Services		71,531		
11		Directors Expenses		83,776		
12		Employee Benefits		9,942		
13		Employee Meeting		6,476		
14		Employee Reimbursable Expense		10,913		
15		Insurance		212,328		
16		Legal Retainers & Fees		41,896		
17		Cash Donations		1,835		
18		Meals & Entertainment		4,639		
19		Meal Allowance		218		
20		Moving		7,418		
21		Industry Dues & Licenses		5,385		
22		Office Expenses		6,119		
23		Supplemental Insurance		91,640		
24		Permits & Filing Fees		874		
25		Postage		1,251		
26		Payroll		1,016,327		
27		Reference Materials		5,586		
28		Rental		113		
29		Seminars & Meeting Registrations		10,940		
30		Software Maintenance		8,666		
31		Training		7,070		
32		**Total MDU Resources Group, Inc.**		$1,725,480	3.5064%	

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2005

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	CENTENNIAL ENERGY	MONTANA-DAKOTA UTILITIES CO.				
2	RESOURCES/CHCC	Communications Department	* Various Corporate Overhead Allocation			
3		Automobile	Factors, Cost of Service Factors, Time	69		
4		Air Service	Studies and /or Actual Costs Incurred	4		
5		Employee Reimbursable Expense		11		
6		Contract Services		44		
7		Materials		24		
8		Office Expenses		103		
9		Office Telephone		11,606		
10		Payroll		7,080		
11		Permits and Filing Fees		28		
12		Organizational Dues		1		
13						
14		Office Services	* General Office Complex and Office			
15		Contract Services	Supplies Cost of Service Allocation	103		
16		Express Mail	Factors	1,364		
17		Postage		1,073		
18		Office Expenses		523		
19		Employee Meetings		4		
20		Cost of Service - General Office Buildings		89,190		21,007
21						
22		Information Systems	* Various Corporate Overhead Allocation			
23		Payroll	Factors and /or Actual Costs Incurred	10,311		
24		Office Expenses		1,620		
25		Office Telephones		316		
26		Contract Services		100		
27						
28		Other Miscellaneous Departments	* Various Corporate Overhead Allocation			
29		Office Supplies	Factors and /or Actual Costs Incurred	9		
30		Payroll		(512)		
31		Automobile		(1)		
32						
33		Other Direct Charges	Actual costs incurred			
34		Employee Discounts		8,884		
35		Corporate/Commercial Air Service		120,386		
36		Computer/Software Costs		137,531		
37		Employee Reimbursable Exp and Fuel		484,268		
38						

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2005

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					
2	RESOURCES/CHCC	Consulting Fees		9,790		
3		Legal Fees		4,108		
4		Telephone		22,472		
5		Building Expenses		83,306		
6		Office Expenses		37,422		
7		Miscellaneous		1,999		
8		**Total Montana-Dakota Utilities Co.**		1,033,239	2.100%	21,007
9						
10		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual costs incurred			
11		Payroll		3,121,315		
12		Federal & State Tax Liability Payments		($9,175,703)		
13		Interest		(8,975)		
14		SISP		75,585		
15		Insurance		9,677		
16		Miscellaneous		92,187		
17		**Total Other Transactions/Reimbursements**		(5,885,914)		
18						
19		**Grand Total Affiliate Transactions**		(3,127,195)	-6.355%	21,007
20						
21		**Total Centennial Energy Resources/CHCC Operating Expenses for 2005**			$49,210,000	
22		**Excludes Intersegment Eliminations**				

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

MONTANA UTILITY INCOME STATEMENT

Year: 2005

	Account Number & Title	Last Year	This Year	% Change
1	400 Operating Revenues	$78,142,776	$97,137,549	24.31%
2				
3	Operating Expenses			
4	401 Operation Expenses	$71,845,630	$89,017,114	23.90%
5	402 Maintenance Expense	731,121	721,942	-1.26%
6	403 Depreciation Expense	1,873,413	2,159,270	15.26%
7	404-405 Amort. & Depl. of Gas Plant	251,449	192,645	-23.39%
8	406 Amort. of Gas Plant Acquisition Adjustments			
9	407.1 Amort. of Property Losses, Unrecovered Plant			
10	& Regulatory Study Costs			
11	407.2 Amort. of Conversion Expense			
12	408.1 Taxes Other Than Income Taxes	2,300,595	2,449,395	6.47%
13	409.1 Income Taxes - Federal	(868,979)	2,686,060	409.11%
14	- Other	(251,944)	763,969	403.23%
15	410.1 Provision for Deferred Income Taxes	494,004	(2,469,418)	-599.88%
16	411.1 (Less) Provision for Def. Inc. Taxes - Cr.	211,011	(307,675)	-245.81%
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**	$76,586,300	$95,213,302	24.32%
21	**NET UTILITY OPERATING INCOME**	$1,556,476	$1,924,247	23.63%

MONTANA REVENUES

SCHEDULE 9

	Account Number & Title	Last Year	This Year	% Change
1	Sales of Gas			
2	480 Residential	$46,458,146	$60,243,176	29.67%
3	481 . Commercial & Industrial - Small	26,446,139	34,727,875	31.32%
4	Commercial & Industrial - Large	28,507	15,754	-44.74%
5	482 Other Sales to Public Authorities			
6	484 Interdepartmental Sales			
7	485 Intracompany Transfers			
8	Net Unbilled Revenue	3,569,672	152,256	-95.73%
9	**TOTAL Sales to Ultimate Consumers**	76,502,464	95,139,061	24.36%
10	483 Sales for Resale			
11	**TOTAL Sales of Gas**	$76,502,464	$95,139,061	24.36%
12	Other Operating Revenues			
13	487 Forfeited Discounts & Late Payment Revenues			
14	488 Miscellaneous Service Revenues	$42,974	$40,711	-5.27%
15	489 Revenues from Transp. of Gas for Others 1/	1,270,808	1,699,694	33.75%
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	232,898	167,200	-28.21%
20	494 Interdepartmental Rents			
21	495 Other Gas Revenues	93,632	90,883	-2.94%
22	**TOTAL Other Operating Revenues**	1,640,312	1,998,488	21.84%
23	**Total Gas Operating Revenues**	$78,142,776	$97,137,549	24.31%
24				
25	496 (Less) Provision for Rate Refunds			
26				
27	**TOTAL Oper. Revs. Net of Pro. for Refunds**	$78,142,776	$97,137,549	24.31%

1/ Includes unbilled revenue.

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2005

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

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2005

	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	$61,750,430	$72,146,521	16.84%
17	805 Other Gas Purchases			
18	805.1 Purchased Gas Cost Adjustments	(1,310,518)	5,688,345	534.05%
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.	11,380,492	15,406,641	35.38%
27	808.2 (Less) Gas Delivered to Storage -Cr.	(11,557,090)	(14,931,280)	-29.20%
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	154,315	103,264	-33.08%
33	**TOTAL Other Gas Supply Expenses**	$60,417,629	$78,413,491	29.79%
34				
35	**TOTAL PRODUCTION EXPENSES**	$60,417,629	$78,413,491	29.79%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2005

	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: 2005

	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	$539,030	$361,345	-32.96%
28	871	Distribution Load Dispatching	57,284	54,302	-5.21%
29	872	Compressor Station Labor and Expenses			
30	873	Compressor Station Fuel and Power			
31	874	Mains and Services Expenses	847,419	836,886	-1.24%
32	875	Measuring & Reg. Station Exp.-General	82,034	32,414	-60.49%
33	876	Measuring & Reg. Station Exp.-Industrial	13,433	4,048	-69.87%
34	877	Meas. & Reg. Station Exp.-City Gate Ck. Sta.	48		-100.00%
35	878	Meter & House Regulator Expenses	415,972	299,701	-27.95%
36	879	Customer Installations Expenses	775,449	704,156	-9.19%
37	880	Other Expenses	882,055	1,007,635	14.24%
38	881	Rents	24,379	27,657	13.45%
39		**Total Operation - Distribution**	$3,637,103	$3,328,144	-8.49%
40	Maintenance				
41	885	Maintenance Supervision & Engineering	$192,462	$162,105	-15.77%
42	886	Maintenance of Structures & Improvements	160	2,138	1236.25%
43	887	Maintenance of Mains	99,524	90,041	-9.53%
44	888	Maint. of Compressor Station Equipment			
45	889	Maint. of Meas. & Reg. Station Exp.-General	39,174	46,452	18.58%
46	890	Maint. of Meas. & Reg. Sta. Exp.-Industrial	13,250	25,949	95.84%
47	891	Maint. of Meas. & Reg. Sta. Equip.-City Gate			
48	892	Maintenance of Services	100,621	65,530	-34.87%
49	893	Maintenance of Meters & House Regulators	80,890	135,746	67.82%
50	894	Maintenance of Other Equipment	64,502	62,573	-2.99%
51		**Total Maintenance - Distribution**	$590,583	$590,534	-0.01%
52		**TOTAL Distribution Expenses**	$4,227,686	$3,918,678	-7.31%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2005

	Account Number & Title		Last Year	This Year	% Change
1					
2		**Customer Accounts Expenses**			
3	Operation				
4	901	Supervision	$173,827	$142,076	-18.27%
5	902	Meter Reading Expenses	595,377	614,264	3.17%
6	903	Customer Records & Collection Expenses	1,308,588	1,322,652	1.07%
7	904	Uncollectible Accounts Expenses	267,713	382,644	42.93%
8	905	Miscellaneous Customer Accounts Expenses	103,860	108,060	4.04%
9					
10		**TOTAL Customer Accounts Expenses**	$2,449,365	$2,569,696	4.91%
11					
12		**Customer Service & Informational Expenses**			
13	Operation				
14	907	Supervision	$1,601	$2,766	72.77%
15	908	Customer Assistance Expenses	26,853	18,605	-30.72%
16	909	Informational & Instructional Advertising Exp.	27,774	15,724	-43.39%
17	910	Miscellaneous Customer Service & Info. Exp.	127	75	-40.94%
18					
19		**TOTAL Customer Service & Info. Expenses**	$56,355	$37,170	-34.04%
20					
21		**Sales Expenses**			
22	Operation				
23	911	Supervision	$83,809	$56,928	-32.07%
24	912	Demonstrating & Selling Expenses	214,362	141,879	-33.81%
25	913	Advertising Expenses	22,133	10,014	-54.76%
26	916	Miscellaneous Sales Expenses	17,941	18,129	1.05%
27					
28		**TOTAL Sales Expenses**	$338,245	$226,950	-32.90%
29					
30		**Administrative & General Expenses**			
31	Operation				
32	920	Administrative & General Salaries	$2,035,726	$1,176,399	-42.21%
33	921	Office Supplies & Expenses	613,955	579,404	-5.63%
34	922	(Less) Administrative Expenses Transferred - Cr.			
35	923	Outside Services Employed	159,669	148,320	-7.11%
36	924	Property Insurance	91,432	81,713	-10.63%
37	925	Injuries & Damages	390,620	387,631	-0.77%
38	926	Employee Pensions & Benefits	1,418,721	1,817,083	28.08%
39	927	Franchise Requirements		1,000	
40	928	Regulatory Commission Expenses	62,123	69,934	12.57%
41	929	(Less) Duplicate Charges - Cr.			
42	930.1	General Advertising Expenses	46,535	46,066	-1.01%
43	930.2	Miscellaneous General Expenses	78,376	74,595	-4.82%
44	931	Rents	49,776	59,518	19.57%
45					
46		**TOTAL Operation - Admin. & General**	$4,946,933	$4,441,663	-10.21%
47	Maintenance				
48	935	Maintenance of General Plant	$140,538	$131,408	-6.50%
49					
50		**TOTAL Administrative & General Expenses**	$5,087,471	$4,573,071	-10.11%
51	**TOTAL OPERATION & MAINTENANCE EXP.**		$72,576,751	$89,739,056	23.65%

MONTANA TAXES OTHER THAN INCOME

Year: 2005

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes	$467,056	$489,210	4.74%
2	Secretary of State	248	286	15.32%
3	Highway Use Tax	196	187	-4.59%
4	Montana Consumer Counsel	85,424	106,547	24.73%
5	Montana PSC	218,098	260,606	19.49%
6	Franchise Taxes	18,821	18,771	-0.27%
7	Property Taxes	1,506,272	1,568,852	4.15%
8	Tribal Taxes	4,480	4,936	10.18%
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50	**TOTAL MT Taxes other than Income**	$2,300,595	$2,449,395	6.47%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 2005

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	A&K Construction Inc.	Construction Services	115,188		0.00%
2					
3	Abateco, Inc.	Abatement Services	146,225		0.00%
4					
5	ADP Proxy Service	Investor Communication Services	206,321	4,606	2.23%
6					
7	Aerial Contractors Inc.	Contract Serv - Memorial Bridge Reroute	303,266		0.00%
8					
9	Agri Industries, Inc.	Contract Services	77,806	11,552	14.85%
10					
11	Amherst Group Limited	Consulting Services	88,401	1,973	2.23%
12					
13	AON Consulting	Consulting Services	116,477	2,600	2.23%
14					
15	Benco Equipment Company	Vehicle Maintenance	189,440	643	0.34%
16					
17	Brown & Saenger	Replace Engineering Cubicles	92,227		0.00%
18					
19	Bullinger Tree Service	Tree Trimming Service	184,099		0.00%
20					
21	Ceda Inc.	Boiler Maintenance	151,771		0.00%
22					
23	Chief Construction	Construction Services	443,291		0.00%
24					
25	Compucom	Software Maintenance	81,031	3,100	3.83%
26					
27	Connecting Point	Computer Service & Software Maintenance	133,445	4,069	0.00%
28					
29	Corridor Exxon Tire & Auto	Vehicle Maintenance	75,181	6,354	8.45%
30					
31	Deloitte & Touche, LLP	Auditing and Consulting Services	233,183	273	0.12%
32					
33	Distribution Construction Co.	Construction Services	255,540		0.00%
34					
35	Diversified Graphics Inc.	Annual Report	175,759	3,923	2.23%
36					
37	DWD LLC	Tree Trimming Service	158,891		0.00%
38					
39	Edison Electric Institute	Membership Fees	86,643		0.00%
40					
41	Ernst & Young, LLP	Consulting Services	87,782	6,098	6.95%
42					
43	Fischer Contracting	Contract Services	113,963		0.00%
44					
45	Floyd Wilson	Consulting Services	118,331	2,641	2.23%
46					
47	Franz Construction	Construction Services	170,419		0.00%
48					
49	Gagnon, Inc	Refractory Repairs	113,445		0.00%
50					

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 2005

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	GE Energy Management Services	Upgrade EMS Computer System	175,555		0.00%
2					
3	GE Energy Services	Construction Services	1,435,460		0.00%
4					
5	Hughes, Kellner, Sullivan	Legal Services	113,526	46,104	40.61%
6					
7	IBA Drilling Co. Inc.	Drilling services	94,965	13,220	13.92%
8					
9	IBM	Contract Services - Computer Maintenance	125,630	17,736	14.12%
10					
11	Industrial Contractors, Inc	Construction Services	1,023,344		0.00%
12					
13	Larson Design Office, Inc.	Contract Services - Office Design	82,180	1,834	2.23%
14					
15	Leboeuf, Lamb, Greene & Macrae	Legal Services	231,787	5,147	2.22%
16					
17	Leonard, Street & Deinard	Legal Services	107,368	118	0.11%
18					
19	Lignite Energy Council	Membership Fees	88,915		0.00%
20					
21	McDermott, Will & Emery	Legal Services	176,184	3,405	1.93%
22					
23	Merril Communications	Contract Services - Stockholder Mtg Mat.	91,706	2,047	2.23%
24					
25	Microsoft	Contract Services - Software Maintenace	689,064	17,641	2.56%
26					
27	Moody's Investors Services	Financial Services	111,800	5,081	4.54%
28					
29	ND Newspaper Association	Advertising	105,926	6,764	6.39%
30					
31	New York Stock Exchange	Financial Services	119,994	2,677	2.23%
32					
33	One Call Locators, LTD	Line Location Service	953,597	164,321	17.23%
34					
35	Outdoor Services Inc.	Contract Services - Meter Reading	936,948	147,976	15.79%
36					
37	Osmose Utilities Service Inc.	Contract Services - Overhead Line Maint.	197,233		0.00%
38					
39	Otter Tail Power Co.	Prelim. Survey & Invest - Big Stone II	600,209		0.00%
40					
41	PA Consulting Services Inc.	Consulting Services	283,904		0.00%
42					
43	Peoplesoft USA Inc.	Software Maintenance	318,845	310	0.10%
44					
45	Petrocomp	Contract Services	406,162		0.00%
46					
47	Pipeling Services of Iowa	Contract Services - Pipeline Installation	156,488		0.00%
48					
49	Pole Maintenance Co.	Contract Services - Pole Treatment	148,085		0.00%
50					

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 2005

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Progressive Maintenance Co.	Custodial Services	99,204	9,143	9.22%
2					
3	Prosource Technologies Inc.	Contract Services - Gas Construction	103,729		0.00%
4					
5	Rocky Mountain Line	Construction Services	153,405		0.00%
6					
7	Siemens Power Technologies Int.	Software License & Maintenance	102,535		0.00%
8					
9	Spring Consulting LLC	Consulting Services	254,137	5,673	2.23%
10					
11	Southern Cross Corporation	Contract Services - Leak Detection	160,156	48,722	30.42%
12					
13	Standard & Poor's	Financial Services	146,314	3,015	2.06%
14					
15	State-Line Contractors, Inc	Construction Services	414,090	399,463	96.47%
16					
17	Swanson & Youngdale, Inc.	Industrial Painting Contractors	279,492		0.00%
18					
19	Sylvan Benefit Consultants	Consulting Services	148,245	2,542	1.71%
20					
21	Thelen Reid & Priest, LLP	Legal Services	887,993	19,070	2.15%
22					
23	The Structure Group	Contract Serv. - Software Install & Maint.	94,318		0.00%
24					
25	Towers Perrin	Consultant - Compensation and Benefits	534,376	24,934	4.67%
26					
27	Ulmer Tree Services	Tree Trimming Service	80,687		0.00%
28					
29	US Bank	Bank Services	163,350	28,824	17.65%
30					
31	Utilities International, Inc.	Consulting Services	139,066	15,630	11.24%
32					
33	Utility Partners, LC	Consultant - Mobile Service Computer	110,787	27,867	25.15%
34					
35	Wells Fargo	Stock Transfer Agent and ESOP Admin	294,362	6,571	2.23%
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51	**TOTAL Payments for Services**		16,859,240	1,073,666	6.37%

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2005

	Description	Total Company	Montana	% Montana
1	Contributions to Candidates by PAC	$11,008	$4,625	42.01%
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43	**TOTAL Contributions**	$11,008	$4,625	42.01%

Pension Costs

Year: 2005

	Item	Current Year	Last Year	% Change
1	Plan Name MDU Resources Group, Inc. Master Pension Plan Trust			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	PROPRIETARY SCHEDULE			
4	PROPRIETARY SCHEDULE			
5				
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year			
8	Service cost			
9	Interest Cost			
10	Plan participants' contributions	PROPRIETARY SCHEDULE		
11	Amendments			
12	Actuarial (Gain) Loss			
13	Acquisition			
14	Benefits paid			
15	Benefit obligation at end of year			
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year			
18	Actual return on plan assets			
19	Acquisition			
20	Employer contribution			
21	Plan participants' contributions	PROPRIETARY SCHEDULE		
22	Benefits paid			
23	Fair value of plan assets at end of year			
24	**Funded Status**			
25	Unrecognized net actuarial loss			
26	Unrecognized prior service cost	PROPRIETARY SCHEDULE		
27	Unrecognized net transition obligation			
28	Accrued benefit cost			
29				
30	**Weighted-average Assumptions as of Year End**			
31	Discount rate	5.50	5.75	-4.35%
32	Expected return on plan assets	8.50	8.50	0.00%
33	Rate of compensation increase	4.25	4.75	-10.53%
34				
35	**Components of Net Periodic Benefit Costs**			
36	Service cost			
37	Interest cost			
38	Expected return on plan assets	PROPRIETARY SCHEDULE		
39	Amortization of prior service cost			
40	Recognized net actuarial gain			
41	Transition amount amortization			
42	Net periodic benefit cost			
43				
44	**Montana Intrastate Costs:**			
45	Pension Costs	PROPRIETARY SCHEDULE		
46	Pension Costs Capitalized			
47	Accumulated Pension Asset (Liability) at Year End			
48	**Number of Company Employees:**			
49	Covered by the Plan			
50	Not Covered by the Plan	PROPRIETARY SCHEDULE		
51	Active			
52	Retired			
53	Deferred Vested Terminated			

Other Post Employment Benefits (OPEBS)

Year: 2005

	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	5.50	5.75	-4.35%
8	Expected return on plan assets	7.50	7.50	0.00%
9	Medical Cost Inflation Rate	6.00	6.00	0.00%
10	Actuarial Cost Method	PROPRIETARY SCHEDULE		
11	Rate of compensation increase	PROPRIETARY SCHEDULE		
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13	**VEBA**			
14	**Describe any Changes to the Benefit Plan:**			
15				
16				
	TOTAL COMPANY			
17	**Change in Benefit Obligation**			
18	Benefit obligation at beginning of year			
19	Service cost			
20	Interest Cost			
21	Plan participants' contributions			
22	Amendments			
23	Actuarial (Gain) Loss			
24	Acquisition			
25	Benefits paid			
26	Benefit obligation at end of year			
27	**Change in Plan Assets**			
28	Fair value of plan assets at beginning of year			
29	Actual return on plan assets			
30	Acquisition			
31	Employer contribution			
32	Plan participants' contributions			
33	Benefits paid			
34	Fair value of plan assets at end of year			
35	**Funded Status**			
36	Unrecognized net actuarial loss			
37	Unrecognized prior service cost			
38	Unrecognized transition obligation			
39	Accrued benefit cost			
40	**Components of Net Periodic Benefit Costs**			
41	Service cost			
42	Interest cost			
43	Expected return on plan assets			
44	Amortization of prior service cost			
45	Recognized net acturial gain			
46	Transition amount amortization			
47	Net periodic benefit cost			
48	**Accumulated Post Retirement Benefit Obligation**			
49	Amount Funded through VEBA			
50	Amount Funded through 401(h)			
51	Amount Funded through Other ____________			
52	TOTAL			
53	Amount that was tax deductible - VEBA			
54	Amount that was tax deductible - 401(h)			
55	Amount that was tax deductible - Other ________			
56	TOTAL			

Other Post Employment Benefits (OPEBS) Continued

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

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

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

COMPENSATION OF TOP 5 CORPORATE EMPLOYEES - SEC INFORMATION

Line No.	Name/Title	Base Salary	Bonuses	Other 1/	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1	Martin A. White - Chairman of the Board & CEO	$697,115	$1,400,000	$514,207	$2,611,322	$2,356,108	11%
2	Terry D. Hildestad - President & COO	433,612	516,194	182,319	1,132,125	624,820	81%
3	Warren L. Robinson - Executive Vice President, & CFO	398,038	637,500	181,407	1,216,945	852,901	43%
4	John K. Castleberry - CEO of WBI Holdings, Inc.	368,846	360,750	178,236	907,832	851,872	7%
5	Bruce T. Imsdahl - President & CEO of Montana-Dakota Utilities Co. and Great Plains Natural Gas Co.	281,827	281,153	53,074	616,054	454,281	36%

1/ See page 20a for details.

EXECUTIVE COMPENSATION

SUMMARY COMPENSATION TABLE

		Annual compensation			Long-term compensation: Awards		Long-term compensation: Payouts	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Name and principal position	Year	Salary ($)	Bonus(1) ($)	Other annual compen-sation(2) ($)	Restricted stock awards ($)(3)	Securities underlying Options/SARs (#)	LTIP payouts ($)	All other compen-sation(7) ($)
Martin A. White	2005	697,115	1,400,000	—	—	—	493,883(4)	20,324(7)
—Chairman of the Board &	2004	647,500	1,265,550	—	—	—	416,724(5)	26,334
CEO	2003	596,308	1,200,000	—	—	—	772,732(6)	6,000
Terry D. Hildestad	2005	433,612	516,194	2,866	—	—	167,948(4)	11,505(7)
—President & COO	2004	348,500	120,925	—	—	—	141,715(5)	13,680
	2003	319,077	252,960	—	—	—	37,013(6)	6,000
Warren L. Robinson	2005	398,038	637,500	2,633	—	—	167,948(4)	10,826(7)
—Executive Vice President	2004	348,500	350,000	—	—	—	141,715(5)	12,686
and CFO(8)	2003	318,154	320,000	—	—	—	267,880(6)	6,000
John K. Castleberry	2005	368,846	360,750	—	—	—	167,948(4)	10,288(7)
—CEO of WBI Holdings,	2004	348,500	350,000	—	—	—	141,715(5)	11,657
Inc.(9)	2003	319,077	320,000	—	—	—	356,567(6)	6,000
Bruce T. Imsdahl	2005	281,827	281,153	826	—	—	43,181(4)	9,067(7)
—President & CEO of	2004	224,000	182,750	—	—	—	41,381(5)	6,150
Montana-Dakota Utilities	2003	193,992	139,739	—	—	—	62,939(6)	5,820
Co. and Great Plains								
Natural Gas Co.								

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

(2) Above-market interest on deferred compensation.

(3) At December 31, 2005, the Named Officers held the following amounts of restricted stock: Mr. White—16,800 shares ($551,880); Mr. Hildestad—5,925 shares ($194,636); Mr. Robinson—5,235 shares ($171,970); Mr. Castleberry—4,740 shares ($155,709); and Mr. Imsdahl—3,060 shares ($100,521).

(4) Represents the value of performance shares earned under the 1997 Executive Long-Term Incentive Plan for the 2003-2005 performance period, which were paid in stock, and dividend equivalents, which were paid in cash.

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

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

(7) Comprised of Company contributions to the Company 401(k) Retirement Plan of $6,300 for each Named Officer and non-preferential dividends on restricted stock, as follows: Mr. White—$14,024; Mr. Hildestad—$5,205; Mr. Robinson—$4,526; Mr. Castleberry—$3,988; and Mr. Imsdahl—$2,767.

(8) Mr. Robinson resigned as Executive Vice President and Chief Financial Officer effective January 3, 2006 and retired effective February 17, 2006.

(9) Mr. Castleberry was elected Executive Vice President—Administration effective March 4, 2006.

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

(a)	(b) Shares acquired on exercise (#) (2)	(c) Value realized ($)	(d) Number of securities underlying unexercised options at fiscal year-end(1) (#)		(e) Value of unexercised, in-the-money options at fiscal year-end ($)	
Name			Exercisable	Unexercisable	Exercisable	Unexercisable
Martin A. White	0	0	0	0	0	0
Terry D. Hildestad	3,683	27,293	0	45,997	0	599,033
Warren L. Robinson	0	0	0	0	0	0
John K. Castleberry	0	0	0	0	0	0
Bruce T. Imsdahl	0	0	0	17,264	0	224,834

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

LONG-TERM INCENTIVE PLANS—AWARDS IN LAST FISCAL YEAR

(a) Name	(b) Number of shares, units or other rights (#)(1)	(c) Performance or other period until maturation or payout	Estimated future payouts under non-stock price-based plans (d) Threshold ($ or #)	(e) Target ($ or #)	(f) Maximum ($ or #)
Martin A. White	35,643	2005-2007	3,564 shares $8,055 Dividend Equivalents	35,643 shares $80,553 Dividend Equivalents	71,286 shares $161,106 Dividend Equivalents
Terry D. Hildestad	12,748	2005-2007	1,275 shares $2,882 Dividend Equivalents	12,748 shares $28,810 Dividend Equivalents	25,496 shares $57,621 Dividend Equivalents
Warren L. Robinson	12,748(2)	2005-2007	1,275 shares $2,882 Dividend Equivalents	12,748 shares $28,810 Dividend Equivalents	25,496 shares $57,621 Dividend Equivalents
John K. Castleberry	12,748	2005-2007	1,275 shares $2,882 Dividend Equivalents	12,748 shares $28,810 Dividend Equivalents	25,496 shares $57,621 Dividend Equivalents
Bruce T. Imsdahl	8,183	2005-2007	818 shares $1,849 Dividend Equivalents	8,183 shares $18,494 Dividend Equivalents	16,366 shares $36,987 Dividend Equivalents

(1) Performance shares were granted in 2005 under the 1997 Executive Long-Term Incentive Plan and represent the opportunity to receive Company Common Stock at the end of the performance period based upon the Company's total shareholder return relative to a peer group of companies. The performance shares shown in column (b) are at the target level. The payout ranges from 0% for a rank less than 40 th percentile, to 10% at the 40 th percentile, 100% at the 50 th percentile and 200% at the 100 th percentile. Dividend equivalents also were granted and will be paid out in cash in an amount equal to the total dividends declared during the performance period on any shares that are actually earned by the participant. Performance shares and dividend equivalents that are not earned are forfeited. Vesting is accelerated upon a change in control.

(2) Mr. Robinson resigned as Executive Vice President and Chief Financial Officer effective January 3, 2006 and retired effective February 17, 2006.

PENSION PLAN TABLE(1)

Remuneration(2)	Years of Service 15	20	25	30	35
$125,000	$ 25,535	$ 34,046	$ 42,558	$ 51,069	$ 59,581
150,000	30,972	41,296	51,620	61,944	72,268
175,000	36,410	48,546	60,683	72,819	84,956
200,000	41,847	55,796	69,745	83,694	97,643
225,000 and Higher	44,022	58,696	73,370	88,044	102,718

(1) The amounts in the Pension Plan Table do not reflect any early retirement reductions.

(2) For 2005, $210,000 is the maximum amount of compensation that can be recognized for purposes of determining benefits under the pension plans.

The Table covers the amounts payable under the Company's qualified pension plans.

Pension benefits are determined by the step-rate formula that places emphasis on the highest consecutive 60 months of earnings within the final 10 years of service. Certain reductions are made for employees electing early retirement.

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 survivorship benefit for spouses, unless participants choose otherwise. Participants who terminate employment before age 55 may elect to receive their benefits in a lump sum.

The pension plans also permit pre-retirement survivorship benefits upon satisfaction of certain conditions.

The Internal Revenue Code places maximum 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 2005, the maximum annual benefits payable under the pension plans is $170,000 and the maximum amount of compensation that can be recognized when determining benefits is $210,000.

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

As of December 31, 2005, the Named Officers were credited with the following years of service under the pension plans:

Name	Pension Service Years
Martin A. White	14
Terry D. Hildestad	32
Warren L. Robinson	17
John K. Castleberry	23
Bruce T. Imsdahl	35

The maximum years of service for benefits under the pension plans is 35. Benefit amounts under the pension plans are not subject to deduction for Social Security or offset amounts.

The Company also maintains a nonqualified retirement plan that provides supplemental retirement benefits (the "SISP"). As of December 31, 2005, 86 senior management personnel, including the Named Officers, participated in the SISP. Retirement benefits under the SISP consist of a monthly benefit commencing on the later of the participant's attainment of age 65, termination of employment or the date elected by the participant (the "Regular SISP Benefit"), and an excess retirement benefit payable up to age 65 if the participant is receiving retirement benefits under one of the Company's qualified pension plans and those benefits are reduced due to limitations under the Internal Revenue Code (the "Excess SISP Benefit").

The Regular SISP Benefits are determined pursuant to a schedule of benefits based on a participant's participation level. Participation levels are determined by the Company's chief executive officer. Based on participation levels as of December 31, 2005, Messrs. White, Hildestad, Robinson, Castleberry and Imsdahl would be entitled to the following annual Regular SISP Benefits: $512,520, $193,320, $193,320, $193,320, and $125,700, respectively. Regular SISP Benefits are payable in monthly installments over a 15 year period or in an actuarial equivalent form elected by the participant.

Participants can elect to receive death benefits rather than Regular SISP Benefits or to receive part of their benefits as retirement benefits and part as death benefits. Based on participation levels as of December 31, 2005, the designated beneficiaries of Messrs. White, Hildestad, Robinson, Castleberry and Imsdahl would be entitled to the following annual death benefits over a 15 year period if the Named Officers elected not to receive any Regular SISP Benefits: $1,025,040, $386,640, $386,640, $386,640, and $251,400, respectively.

Excess SISP Benefits are equal to the difference between (1) the monthly retirement benefits that would have been payable to the participant under the Company's qualified pension plans absent the limitations under the Internal Revenue Code and (2) the actual benefits payable to the participant under the qualified pension plans. The Excess SISP Benefits are only payable if the participant commences receipt of benefits under the Company's qualified pension plans prior to age 65. If payable, benefits commence when benefits under the Company's qualified pension plans commence and continue up to age 65 or the death of the participant, if prior to age 65, and, if applicable, in reduced amount until the death of the participant's spouse or joint annuitant, as applicable. If the employment of a participant whose pension plan benefits are limited under the Internal Revenue Code (therefore entitling the participant to an Excess SISP Benefit) is severed before the participant reaches the age of 55, and the participant chooses to receive his or her pension plan benefit in the form of a lump-sum payment, the participant will receive the Excess SISP Benefit in the form of a lump-sum payment. Because of the age 55 limitation, Mr. Castleberry is the only Named Officer who could receive his Excess SISP Benefit in the form of a lump-sum payment. Based on compensation levels reflected in the Summary Compensation Table and Internal Revenue Code limitations applicable in 2005, if the Named Officers had retired on December 31, 2005, Messrs. White, Hildestad, Robinson, Castleberry and Imsdahl would have been entitled to the following annual Excess SISP Benefits until age 65: $79,402, $57,396, $36,393, $22,810, and $9,492, respectively, assuming the participants elected to receive their benefits under the qualified pension plans in the form of a straight life annuity. The Named Officers' current ages are 64, 56, 55, 51, and 57, respectively. None of the Named Officers are currently receiving benefits under the Company's qualified pension plans.

Each of the Named Officers is fully vested in his Regular SISP Benefit and Excess SISP Benefit. Benefits under the SISP are not reduced for Social Security or other offset amounts.

CHANGE-OF-CONTROL AND SEVERANCE ARRANGEMENTS

The Company entered into Change of Control Employment Agreements with the Named Officers and other executives ("executives") in November 1998, May 2004, and February 2006, which provide certain protections to the executives in the event there is a change of control of the Company.

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

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

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

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

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

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

The Company entered into an agreement with Warren L. Robinson on November 23, 2005 in connection with his retirement as Executive Vice President and Chief Financial Officer of the Company effective January 3, 2006. Mr. Robinson agreed to continue as a special projects advisor for the Company through February 17, 2006. Mr. Robinson received a severance payment of $1,000,000. Mr. Robinson holds annual and long-term incentive awards which have been or will be paid out based upon Company performance in accordance with the terms of the awards. Other benefits to which Mr. Robinson is entitled are determined in accordance with the terms and provisions of the Company's plans and programs.

Effective March 4, 2006, John K. Castleberry became Executive Vice President—Administration of the Company. His agreement provides for (i) a base salary of $300,000; (ii) a one-time performance bonus of up to $250,000; (iii) 2006 EICP awards with a target award of 50% of base salary (prorated with two months at his salary as CEO of WBI Holdings, Inc. and ten months at his salary as Executive Vice President—Administration at the Company); (iv) 6,499 performance shares under the LTIP, with a target award of 75% of base salary; (v) a supplemental lump sum pension payment to cover any pension shortfall upon his retirement; (vi) a supplemental payment to cover any SISP shortfall upon his retirement; and (vii) participation at a level 67 SISP category, which results in an annual survivor's benefit of $468,600 for 15 years or an annual retirement benefit of $234,300 for 15 years.

COMPENSATION COMMITTEE REPORT ON EXECUTIVE COMPENSATION

Purpose

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

Executive Compensation Philosophy

The Committee believes that appropriate compensation levels succeed in both attracting and motivating high quality employees. To implement this philosophy, the Committee analyzes trends in compensation among comparable companies participating in the oil and gas industry, segments of the energy and mining industries, the peer group of companies used in the graph following this report, and similar companies from general industry. The Committee uses outside consultants for surveys and other information as it deems appropriate. The Committee then sets compensation levels that it believes are competitive within the industry and structured in a manner that rewards successful job performance. The Committee looks at compensation packages as a whole in determining target levels of compensation including prior incentive awards. The Committee also believes that executive officers should have more of their compensation at risk than other employees. There are three components of total executive compensation: base salary, annual incentive compensation, and long-term incentive compensation.

The following discussion relates to the named executive officers other than Mr. White. Mr. White's compensation is discussed below in a separate section of this report.

Base Salary

In setting base salaries, the Committee does not use a particular formula. In addition to the above data, other factors the Committee uses in its analysis include the executive's current salary in comparison to the competitive industry standard as well as individual performance and experience. For the named officers, the Committee targeted salaries at the midpoint of the competitive industry standard. The raises each named officer received varied from the midpoint based upon individual performance levels and experience. Messrs. Hildestad, Robinson and Castleberry received base salary increases averaging 15.43% for 2005. Mr. Hildestad received an additional 28.4% increase in base salary in connection with his appointment as President and Chief Operating Officer of the Company effective May 1, 2005, and Mr. Robinson received an additional 14.9% increase in base salary effective June 1, 2005. Mr. Imsdahl received a salary increase effective November 2004 in connection with his appointment as President and Chief Executive Officer of Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. and received no further increase in 2005.

Incentive Compensation

In keeping with the Committee's belief that compensation should be directly linked to successful performance, the Company has established both annual and long-term incentive compensation plans. In addition, the Committee has adopted a policy limiting annual incentive compensation payments above targeted incentive amounts to ensure only a portion of incremental earnings above budget are paid to executive participants.

Annual Incentive Compensation

On February 14, 2006, the Committee approved the payment of annual awards under the existing executive incentive compensation plans with respect to 2005. On February 16, 2006, the Board approved the payments. These payments are included in the Bonus column of the Summary Compensation Table.

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

The performance goals for the 2005 annual incentive under the 1997 Executive Long-Term Incentive Plan, which applied to Mr. Hildestad and Mr. Robinson, were (i) budgeted earnings per share achieved (weighted 75%) and (ii) budgeted return on invested capital achieved (weighted 25%). Achievement of budgeted levels of earnings per share and return on invested capital would result in a potential award of 100% of the target amount. Achievement of less than 85% would result in no payment, while achievement of 114% would result in a payment of 200% of the target amount. Mr. Hildestad's award opportunity under this plan was targeted at 75% of his base salary as President and Chief Operating Officer, which was set at the time of his promotion, effective May 1, 2005, and Mr. Robinson's award was targeted at 50% of his base salary. The goals were met at the maximum level ($2.29 EPS, 10.8% ROIC) and resulted in a payment of 200% of the target amount to Messrs. Hildestad and Robinson.

In addition to his incentive award under this plan (which was prorated to reflect the eight months he served as the Company's President and Chief Executive Officer during 2005), Mr. Hildestad also received an award under the Knife River Corporation Executive Incentive Compensation Plan (prorated to reflect the four months he served as President and Chief Executive Officer of Knife River Corporation during 2005). The performance goals for 2005 under the Knife River Corporation Executive Incentive Compensation Plan were based upon (i) actual earnings per allocated share as a percentage of planned earnings per allocated share (weighted 75%) and (ii) return on invested capital as a percentage of planned return on invested capital (weighted 25%). Achievement of budgeted levels of earnings per allocated share and return on invested capital would result in a potential award of 100% of the target amount. Achievement of less than 80% would result in no payment, while achievement of 120% would result in a payment of 200% of the target amount. The target amounts were $1.31 EPS and 7.10% ROIC. Mr. Hildestad's award under the Knife River Corporation Executive Incentive Compensation Plan was earned at less than target on a weighted basis and resulted in a payment of 67% of the target amount.

In addition to his original incentive opportunity discussed above, Mr. Robinson received an incentive award for a June 1, 2005 through December 31, 2005 performance period. The award was subject to the achievement of the same weighted performance goals, and carried the same potential percentage payouts, as described above. This award opportunity was targeted at 47.48% of Mr. Robinson's base salary during the performance period, prorated to reflect the seven month performance period. The goals were met at the maximum level and resulted in a payment of 200% of the target amount.

Mr. Castleberry received his award pursuant to the WBI Holdings, Inc. Executive Incentive Compensation Plan, based upon (i) actual earnings per allocated share as a percentage of targeted earnings per allocated share (weighted 75%) and (ii) actual return on invested capital as a percentage of targeted return on invested capital (weighted 25%) for WBI Holdings, Inc. The target amounts were $3.09 EPS, 13.5% ROIC. Mr. Castleberry's award was targeted at 50% of his base salary and was earned at 200% of target on a weighted basis and resulted in a potential payment of 200% of the target amount. Mr. Castleberry's actual award payment pursuant to the above guidelines was equal to 95% of the potential payment amount. Payment of an additional 5% of the potential amount was contingent on the achievement of Company-wide safety-related goals. The safety related goals were partially met and Mr. Castleberry received an additional 2.5% of the potential payment amount.

Mr. Imsdahl received his award pursuant to the Montana-Dakota Utilities Co. Executive Incentive Compensation Plan, based upon (i) actual earnings per allocated share as a percentage of targeted earnings per allocated share (weighted 75%) and (ii) actual return on invested capital as a percentage of targeted return on invested capital (weighted 25%) for Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. The target amounts were $0.61 EPS, 6.268% ROIC. Mr. Imsdahl's award was targeted at 50% of his base salary and was earned near the maximum level on a weighted basis and resulted in a payment of 197% of the target amount.

Long-Term Incentive Compensation

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

Based upon a study of the Company's executive compensation programs in 2002, the Committee made several changes to its approach to the long-term incentive compensation, including the elimination of stock options and restricted stock grants effective in 2003. The Committee does not expect to make additional stock option or restricted stock grants under the 1997 Executive Long-Term Incentive Plan. Beginning with grants made in 2003, the Committee is using performance shares, with dividend equivalents, as the form of long-term incentive compensation. Performance shares represent the opportunity to receive Company Common Stock at the end of the performance period based upon the Company's total shareholder return ("TSR") relative to the same peer group of companies used in the Performance Graph. Dividend equivalents represent the opportunity to receive cash in an amount equal to the total dividends declared during the performance period on any shares that are actually earned. These awards are expected to be made annually. This long-term award is designed to ensure the retention value and the motivation effect of the Company's long-term compensation program on the Company's executive officers.

Awards for the 2005-2007 performance period were made to the named officers in 2005. The level of award for each executive officer was determined by using the Committee approved target incentive guidelines. The performance share awards were targeted at 75% to 90% of base salary. The payouts will range from 0% for a TSR rank less than the 40 th percentile, to 10% at the 40 th percentile, 100% at the 50 th percentile and 200% at the 100 th percentile.

Awards for the 2003-2005 performance period were granted to executive officers in 2003. These awards were earned at the 118% level, which reflects TSR performance at the 59 th percentile. As a result, the named executive officers received a payment of Company Common Stock and cash equal to the dividend equivalents. These amounts are disclosed in the LTIP Payout column in the Summary Compensation Table.

The Committee granted shares of restricted stock to the executive officers in 2000. Vesting of 54% of these shares was accelerated after the first performance cycle (2000-2002) based upon achievement of TSR goals at the 54 th percentile. TSR in comparison to the proxy peer group for the second performance cycle (2003-2005) resulted in acceleration of vesting of the remaining shares. The named executive officers received shares as follows: Mr. Hildestad-3,450 shares; Mr. Robinson-2,760 shares; Mr. Castleberry-2,760 shares; and Mr. Imsdahl-2,070 shares.

CEO Compensation

The Committee reviewed the total amount of Mr. White's compensation and believes that it is reasonable. His 2005 compensation was comprised of base salary, annual incentive and long-term incentive. During 2005, only approximately 23.7% of Mr. White's compensation was base pay, with the remainder being performance-based. This reflects the Committee's belief in the importance of having substantial at risk compensation to provide a direct and strong link between performance and executive pay.

Mr. White received a 7.7% increase in base salary for 2005, from $650,000 to $700,000.

Mr. White's annual incentive award opportunity was based on (i) budgeted earnings per share achieved (weighted 75%) and (ii) budgeted return on invested capital (weighted 25%). Achievement of the goals at less than 85% would result in no payment, while achievement of 100% would result in a payment of 100% of the target amount and achievement of 114% would result in a payment of 200% of the target amount. Mr. White's award was targeted at 100% of his base salary for 2005 based on executive salary structure and target incentive guidelines approved by the Committee. The goals were met at the maximum level ($2.29 EPS, 10.8% ROIC) and resulted in a payment of 200% of the target amount. This amount is disclosed in the Bonus column in the Summary Compensation Table.

Mr. White received an award of performance shares for the 2005-2007 performance period. His target award was at 133% of his base salary. As discussed above, performance shares represent the opportunity to receive Company Common Stock at the end of the performance period based upon the Company's total shareholder return relative to the proxy group of companies. The payout ranges from 0% for a rank less than the 40 th percentile, to 10% at the 40 th percentile, 100% at the 50 th percentile and 200% at the 100 th percentile. Dividend equivalents were also granted and will be paid out in cash in an amount equal to the total dividends declared during the performance period on any shares that are actually earned.

Awards for the 2003-2005 performance period were granted to Mr. White in 2003 and were earned at the 118% level, reflecting TSR performance at the 59 th percentile. As a result, Mr. White received a payment of Company Common Stock and cash equal to the dividend equivalents. These amounts are disclosed in the LTIP Payout column in the Summary Compensation Table.

Mr. White also received 6,900 shares of Company Common Stock when vesting of the remaining restricted stock awards granted in 2000 was accelerated based on TSR achieved at the 54 th percentile for the second performance cycle (2003-2005).

Repayment of Incentive Compensation

The Committee adopted incentive repayment guidelines at its February 2005 meeting that allow the Committee to secure repayment from, or to make additional payments to, senior officers if Company accounting restatements occur within three years after incentive payments have been made. The Committee may rescind award vesting, rescind vesting acceleration, require award forfeiture or require cash repayment.

Stock Ownership Guidelines

In 1993, the Board of Directors adopted Stock Ownership Guidelines under which executives are required to own Company Common Stock valued from one to four times their annual salary. In 2005, the Board adopted Stock Ownership Guidelines for non-employee directors of five times their annual cash retainer.

Section 162(m)

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

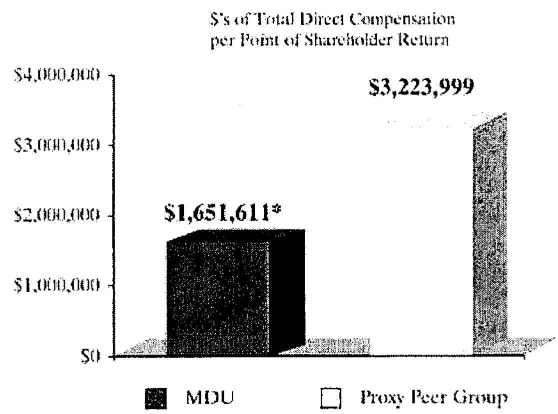
2005 Executive Compensation Analysis

In 2004 the Compensation Committee requested an analysis by the Company's human resources department of the value of the Company's executive compensation program. Specifically, the Committee sought to determine whether or not the relationship between the level of compensation and shareholder return was more favorable than that of the proxy peer group. In 2005 the Compensation Committee requested an update of the analysis.

The 2005 analysis consisted of comparing what the Company paid its named executive officers for the years 2000 through 2004 to the Company's average annual total shareholder return over the same five-year period. The Company's pay ratio was compared to the ratios of companies in the proxy peer group. (1)

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

5 Year Total Direct Compensation
to 5 Year Shareholder Return



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

The results of the analysis showed that the Company paid its named executive officers significantly less than what the peer group companies paid their named executive officers for comparable levels of shareholder return over the five-year period (see the above graph). **Specifically, the Company paid its named executives approximately $1.6 million less per point of shareholder return than the proxy peer group. The Committee views these results as confirmation that MDU Resources Group, Inc.'s stockholders receive high value for the compensation paid to Company executives. Additionally, the results improved when compared to the results contained in last year's proxy statement.**

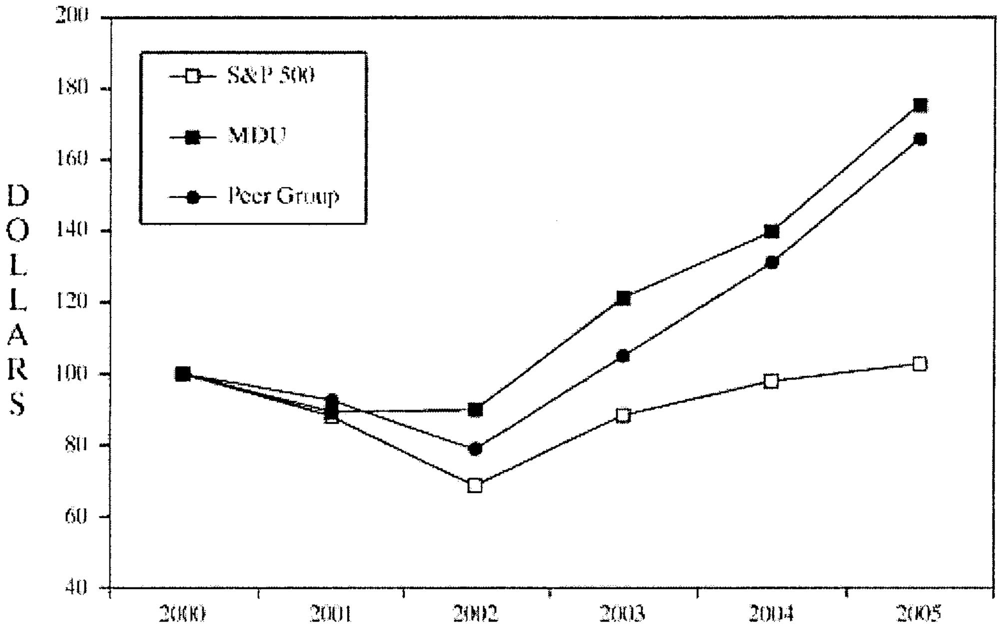
Harry J. Pearce, Chairman
Thomas Everist, Member
Karen B. Fagg, Member
Dennis W. Johnson, Member
Richard H. Lewis, Member
Patricia L. Moss, Member

(1) Vectren Corporation was not included because full five-year data was not available. Vectren Corporation was formed in 2000 by a merger of Indiana Energy, Inc. and SIGCORP.

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

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

Total Stockholder Return Index (2000=100)



	2000	2001	2002	2003	2004	2005
S&P 500	100.00	88.11	68.64	88.33	97.94	102.75
MDU	100.00	89.34	89.90	121.10	139.53	175.37
Peer Group	100.00	92.66	78.83	104.85	130.82	165.71

(1) All data is indexed to December 31, 2000, for the Company, the S&P 500, and the Peer Group. Total stockholder return is calculated using the December 31 price for each year. It is assumed that all dividends are reinvested in stock at the frequency paid, and the returns of each component peer issuer of the group is weighted according to the issuer's stock market capitalization at the beginning of the period.

Peer Group issuers are Allegheny Energy, Inc., Allete, Inc., Alliant Energy Corporation, Black Hills Corporation, Comstock Resources, Inc., Equitable Resources, Inc., Florida Rock Industries, Inc., Hanson PLC ADR, KeySpan Corporation, Kinder Morgan, Inc., Martin Marietta Materials, Inc., Newfield Exploration Company, NICOR, Inc., OGE Energy Corp., ONEOK, Inc., Peoples Energy Corporation, Pogo Producing Company, Quanta Services, Inc., Questar Corporation, SCANA Corporation, Stone Energy Corporation, TECO Energy, Inc., UGI Corporation, Vectren Corporation (formerly Indiana Energy, Inc.), Vulcan Materials Company, and XTO Energy, Inc. (formerly Cross Timbers Oil Company).

BALANCE SHEET

Year: 2005

	Account Number & Title		Last Year	This Year	% Change
1		**Assets and Other Debits**			
2	Utility Plant				
3	101	Gas Plant in Service	$224,176,847	$233,794,882	4.29%
4	101.1	Property Under Capital Leases			
5	102	Gas Plant Purchased or Sold			
6	104	Gas Plant Leased to Others	25,772	25,772	0.00%
7	105	Gas Plant Held for Future Use			
8	105.1	Production Properties Held for Future Use			
9	106	Completed Constr. Not Classified - Gas			
10	107	Construction Work in Progress - Gas	2,643,604	4,134,840	56.41%
11	108	(Less) Accumulated Depreciation	(141,061,279)	(146,801,896)	4.07%
12	111	(Less) Accumulated Amortization & Depletion	(824,835)	(770,117)	-6.63%
13	114	Gas Plant Acquisition Adjustments	12,606,238	12,606,238	0.00%
14	115	(Less) Accum. Amort. Gas Plant Acq. Adj.	(2,278,849)	(2,757,496)	21.00%
15	116	Other Gas Plant Adjustments			
16	117	Gas Stored Underground - Noncurrent	3,022,878	2,892,328	-4.32%
17	118	Other Utility Plant	674,433,879	695,053,405	3.06%
18	119	Accum. Depr. and Amort. - Other Utl. Plant	(389,289,705)	(408,892,160)	5.04%
19		**TOTAL Utility Plant**	$383,454,550	$389,285,796	1.52%
20	**Other Property & Investments**				
21	121	Nonutility Property	$1,511,061	$2,443,473	61.71%
22	122	(Less) Accum. Depr. & Amort. of Nonutil. Prop.	(498,029)	(829,525)	66.56%
23	123	Investments in Associated Companies			
24	123.1	Investments in Subsidiary Companies	1,479,846,408	1,679,383,163	13.48%
25	124	Other Investments	33,381,533	35,253,698	5.61%
26	125	Sinking Funds			
27		**TOTAL Other Property & Investments**	$1,514,240,973	$1,716,250,809	13.34%
28	**Current & Accrued Assets**				
29	131	Cash	$1,593,384	$5,373,898	237.26%
30	132-134	Special Deposits	1,200	1,200	0.00%
31	135	Working Funds	40,596	41,215	1.52%
32	136	Temporary Cash Investments	7,142,665	10,150,233	42.11%
33	141	Notes Receivable			
34	142	Customer Accounts Receivable	29,563,788	50,421,682	70.55%
35	143	Other Accounts Receivable	4,471,664	1,845,962	-58.72%
36	144	(Less) Accum. Provision for Uncollectible Accts.	(270,046)	(437,714)	62.09%
37	145	Notes Receivable - Associated Companies			
38	146	Accounts Receivable - Associated Companies	20,736,266	24,451,470	17.92%
39	151	Fuel Stock	2,831,449	2,976,919	5.14%
40	152	Fuel Stock Expenses Undistributed			
41	153	Residuals and Extracted Products			
42	154	Plant Materials and Operating Supplies	6,614,811	6,912,703	4.50%
43	155	Merchandise	1,272,501	1,441,219	13.26%
44	156	Other Material & Supplies			
45	163	Stores Expense Undistributed	24,487		-100.00%
46	164.1	Gas Stored Underground - Current	21,773,200	21,165,381	-2.79%
47	165	Prepayments	7,074,369	6,032,773	-14.72%
48	166	Advances for Gas Explor., Devl. & Production			
49	171	Interest & Dividends Receivable			
50	172	Rents Receivable			
51	173	Accrued Utility Revenues	42,306,751	45,345,150	7.18%
52	174	Miscellaneous Current & Accrued Assets	178,863	256,692	43.51%
53		**TOTAL Current & Accrued Assets**	$145,355,948	$175,978,783	21.07%

BALANCE SHEET

Year: 2005

	Account Number & Title		Last Year	This Year	% Change
1		**Assets and Other Debits (cont.)**			
2					
3	**Deferred Debits**				
4					
5	181	Unamortized Debt Expense	$1,466,592	$894,805	-38.99%
6	182.1	Extraordinary Property Losses			
7	182.2	Unrecovered Plant & Regulatory Study Costs			
	182.3	Other Regulatory Assets	3,333,602	2,797,718	-16.08%
	183	Prelim. Electric Survey & Investigation Chrg.	1,424,297	3,989,782	180.12%
8	183.1	Prelim. Nat. Gas Survey & Investigation Chrg.		3,310	100.00%
9	183.2	Other Prelim. Nat. Gas Survey & Invtg. Chrgs.			
10	184	Clearing Accounts	(149,815)	(151,263)	0.97%
11	185	Temporary Facilities			
12	186	Miscellaneous Deferred Debits	26,759,428	23,904,554	-10.67%
13	187	Deferred Losses from Disposition of Util. Plant			
14	188	Research, Devel. & Demonstration Expend.			
15	189	Unamortized Loss on Reacquired Debt	3,531,307	3,160,191	-10.51%
16	190	Accumulated Deferred Income Taxes	26,215,669	30,075,911	14.72%
17	191	Unrecovered Purchased Gas Costs	15,533,707	690,765	-95.55%
18	192.1	Unrecovered Incremental Gas Costs			
19	192.2	Unrecovered Incremental Surcharges			
20		**TOTAL Deferred Debits**	$78,114,787	$65,365,773	-16.32%
21					
22	**TOTAL ASSETS & OTHER DEBITS**		$2,121,166,258	$2,346,881,161	10.64%
	Account Number & Title		Last Year	This Year	% Change
23		**Liabilities and Other Credits**			
24					
25	**Proprietary Capital**				
26					
27	201	Common Stock Issued	$118,586,065	$120,262,786	1.41%
28	202	Common Stock Subscribed			
29	204	Preferred Stock Issued	15,000,000	15,000,000	0.00%
30	205	Preferred Stock Subscribed			
31	207	Premium on Capital Stock	866,861,363	912,418,421	5.26%
32	211	Miscellaneous Paid-In Capital			
33	213	(Less) Discount on Capital Stock			
34	214	(Less) Capital Stock Expense	(3,412,569)	(3,412,569)	0.00%
35	216	Appropriated Retained Earnings	43,802,615	48,122,299	9.86%
36	216.1	Unappropriated Retained Earnings	655,292,626	836,672,917	27.68%
37	217	(Less) Reacquired Capital Stock	(3,625,813)	(3,625,812)	0.00%
38	219	Accumulated Other Comprehensive Income	(11,491,485)	(33,816,131)	-194.27%
39		**TOTAL Proprietary Capital**	$1,681,012,802	$1,891,621,911	12.53%
40					
41	**Long Term Debt**				
42					
43	221	Bonds	$145,850,000	$125,000,000	-14.30%
44	222	(Less) Reacquired Bonds			
45	223	Advances from Associated Companies			
46	224	Other Long Term Debt	38,100,000	61,000,000	60.10%
47	225	Unamortized Premium on Long Term Debt			
48	226	(Less) Unamort. Discount on Long Term Debt-Dr.	(32,226)	(27,781)	-13.79%
49		**TOTAL Long Term Debt**	$183,917,774	$185,972,219	1.12%

BALANCE SHEET

Year: 2005

	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	$1,046,120	$1,098,206	4.98%
9	228.3	Accumulated Provision for Pensions & Benefits	38,777,977	37,496,669	-3.30%
10	228.4	Accumulated Misc. Operating Provisions			
11	229	Accumulated Provision for Rate Refunds		692,276	100.00%
12	230	Asset Retirement Obligations	646,150	2,258,805	249.58%
13		**TOTAL Other Noncurrent Liabilities**	$40,470,247	$41,545,956	2.66%
14					
15	**Current & Accrued Liabilities**				
16					
17	231	Notes Payable	$0	$0	0.00%
18	232	Accounts Payable	30,776,542	41,434,341	34.63%
19	233	Notes Payable to Associated Companies			
20	234	Accounts Payable to Associated Companies	7,930,615	10,185,274	28.43%
21	235	Customer Deposits	1,845,929	2,142,110	16.05%
22	236	Taxes Accrued	9,081,392	11,005,242	21.18%
23	237	Interest Accrued	2,047,469	1,930,553	-5.71%
24	238	Dividends Declared	21,449,171	22,950,510	7.00%
25	239	Matured Long Term Debt			
26	240	Matured Interest			
27	241	Tax Collections Payable	1,618,279	2,441,357	50.86%
28	242	Miscellaneous Current & Accrued Liabilities	22,696,729	22,034,050	-2.92%
29	243	Obligations Under Capital Leases - Current			
30		**TOTAL Current & Accrued Liabilities**	$97,446,126	$114,123,437	17.11%
31					
32	**Deferred Credits**				
33					
34	252	Customer Advances for Construction	$1,702,239	$1,978,144	16.21%
35	253	Other Deferred Credits	21,674,170	26,475,796	22.15%
36	254	Other Regulatory Liabilities	12,186,926	11,509,917	-5.56%
37	255	Accumulated Deferred Investment Tax Credits	1,869,757	1,370,153	-26.72%
38	256	Deferred Gains from Disposition Of Util. Plant			
39	257	Unamortized Gain on Reacquired Debt			
40	281-283	Accumulated Deferred Income Taxes	80,886,217	72,283,628	-10.64%
41		**TOTAL Deferred Credits**	$118,319,309	$113,617,638	-3.97%
42					
43	**TOTAL LIABILITIES & OTHER CREDITS**		$2,121,166,258	$2,346,881,161	10.64%

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 mining, independent power production, 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 mining, independent power production, and other are nonregulated. For further descriptions of the Company's businesses, see Note 13. The statements also include the ownership interests in the assets, liabilities and expenses of two jointly owned electric generating facilities.

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

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

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

Cash and cash equivalents

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

Allowance for doubtful accounts

The Company's allowance for doubtful accounts as of December 31, 2005 and 2004, was $8.0 million and $6.8 million, respectively.

Natural gas in underground storage

Natural gas in underground storage for the Company's regulated operations is carried at cost using the last-in, first-out method. The portion of the cost of natural gas in underground storage expected to be used within one year was included in inventories and was $24.7 million and $24.9 million at December 31, 2005 and 2004, respectively. The remainder of natural gas in underground storage was included in other assets and was $43.2 million and $43.3 million at December 31, 2005 and 2004, respectively.

Inventories

Inventories, other than natural gas in underground storage for the Company's regulated operations, consisted primarily of aggregates held for resale of $78.1 million and $71.0 million, materials and supplies of $48.7 million and $31.0 million, and other inventories of $20.7 million and $17.0 million, as of December 31, 2005 and 2004, respectively. These inventories were stated at the lower of cost or market.

Property, plant and equipment

Additions to property, plant and equipment are recorded at cost when first placed in service. 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, $6.2 million and $7.4 million in 2005, 2004 and 2003, respectively. Generally, property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except for depletable reserves, which are depleted based on the units-of-production method based on recoverable aggregate reserves, and natural gas and oil production properties, which are amortized on the units-of-production method based on total reserves.

Property, plant and equipment at December 31, 2005 and 2004, was as follows:

	2005	2004	Estimated Depreciable Life in Years
	(Dollars in thousands, as applicable)		
Regulated:			
Electric:			
Electric generation, distribution and transmission plant	$670,771	$650,902	4-50
Natural gas distribution:			
Natural gas distribution plant	277,288	264,496	4-45
Pipeline and energy services:			
Natural gas transmission, gathering and storage facilities	374,646	358,853	8-104
Nonregulated:			
Construction services:			
Land	2,533	2,533	---
Buildings and improvements	12,063	10,257	3-40
Machinery, vehicles and equipment	67,439	63,586	2-10
Other	8,075	6,224	3-10
Pipeline and energy services:			
Natural gas gathering and other facilities	146,662	132,067	3-20
Energy services	1,488	1,480	3-7
Natural gas and oil production:			
Natural gas and oil properties	1,280,960	973,604	*
Other	22,487	9,021	3-15
Construction materials and mining:			
Land	91,613	91,610	---
Buildings and improvements	87,550	51,309	1-40
Machinery, vehicles and equipment	738,568	658,355	1-20
Construction in progress	15,687	16,545	---
Aggregate reserves	377,008	372,649	**
Independent power production:			
Electric generation	154,880	154,631	10-30
Construction in progress	234,279	93,953	---
Land	375	375	---
Other	2,077	1,643	3-7
Other:			
Land	2,919	3,044	---
Other	24,987	14,291	3-40
Less accumulated depreciation, depletion and amortization	1,544,462	1,358,723	
Net property, plant and equipment	$3,049,893	$2,572,705	

* *Amortized on the units-of-production method based on total proved reserves at an Mcf equivalent average rate of $1.19, $.98 and $.89 for the years ended December 31, 2005, 2004 and 2003, respectively. Includes natural gas and oil production properties accounted for under the full-cost method, of which $82.3 million and $69.0 million were excluded from amortization at December 31, 2005 and 2004, respectively.*

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

Impairment of long-lived assets

The Company reviews the carrying values of its long-lived assets, excluding goodwill and natural gas and oil properties, whenever events or changes in circumstances indicate that such carrying values may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. In the third quarter of 2004, the Company recognized a $2.1 million ($1.3 million after tax) adjustment reflecting the reduction in value of certain gathering facilities in the Gulf Coast region at the pipeline and energy services segment. No impairment losses were recorded in 2005 and 2003. Unforeseen events and changes in circumstances could require the recognition of other impairment losses at some future date.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net tangible and intangible assets acquired in a business combination. Goodwill is required to be tested for impairment annually, or more frequently if events or changes in circumstances indicate that goodwill may be impaired. In the third quarter of 2004, the Company recognized a goodwill impairment at the pipeline and energy services segment. No goodwill impairment losses were recorded in 2005 and 2003. For more information on the goodwill impairment and goodwill, see Note 3.

Natural gas and oil properties

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

At December 31, 2005 and 2004, the Company's full-cost ceiling exceeded the Company's capitalized cost. However, sustained downward movements in natural gas and oil prices subsequent to December 31, 2005, 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, 2005, in total and by the year in which such costs were incurred:

		Year Costs Incurred			
	Total	2005	2004	2003	2002 and prior
		(In thousands)			
Acquisition	$38,971	$13,723	$3,180	$ 481	$21,587
Development	25,586	15,805	7,567	450	1,764
Exploration	10,124	9,899	225	---	---
Capitalized interest	7,610	2,556	2,039	687	2,328
Total costs not subject to amortization	$82,291	$41,983	$13,011	$1,618	$25,679

Costs not subject to amortization as of December 31, 2005, consisted primarily of unevaluated leaseholds, drilling costs and seismic costs; and capitalized interest associated primarily with coalbed development in the Powder River Basin of Montana and Wyoming, an exploration project in southern Texas, an enhanced recovery development project in the Cedar Creek Anticline in southeastern Montana, the Bakken Play in western North Dakota, and a Red River B prospect in western South Dakota. The Company expects that the majority of these costs will be evaluated within the next five years and included in the amortization base as the properties are developed and evaluated and proved reserves are established or impairment is determined.

Revenue recognition

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

Percentage-of-completion method

The Company recognizes construction contract revenue from fixed-price and modified fixed-price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. If a loss is anticipated on a contract, the loss is immediately recognized. Costs in excess of billings on uncompleted contracts of $52.3 million and $31.9 million at December 31, 2005 and 2004, respectively, represent revenues recognized in excess of amounts billed and were included in receivables, net. Billings in excess of costs on uncompleted contracts of $50.7 million and $32.2 million at December 31, 2005 and 2004, respectively, represent billings in excess of revenues recognized and were included in accounts payable. Also included in receivables, net, were amounts representing balances billed but not paid by customers under retainage provisions in contracts that amounted to $59.5 million and $40.9 million at December 31, 2005 and 2004, respectively, which are expected to be paid within one year or less.

Derivative instruments

The Company's policy allows the use of derivative instruments as part of an overall energy price, foreign currency and interest rate risk management program to efficiently manage and minimize commodity price, foreign currency and interest rate risk. The Company's policy prohibits the use of derivative instruments for speculating to take advantage of market trends and conditions, and the Company has procedures in place to monitor compliance with its policies. The Company is exposed to credit-related losses in relation to derivative instruments in the event of nonperformance by counterparties. The Company's policy requires that natural gas and oil price derivative instruments and interest rate derivative instruments not exceed a period of 24 months and foreign currency derivative instruments not exceed a 12-month period. The Company's policy requires settlement of natural gas and oil price derivative instruments monthly and all interest rate derivative transactions must be settled over a period that will not exceed 90 days, and any foreign currency derivative transaction settlement periods may not exceed a 12-month period. The Company has policies and procedures that management believes minimize credit-risk exposure. These policies and procedures include an evaluation of potential counterparties' credit ratings and credit exposure limitations. Accordingly, the Company does not anticipate any material effect on its financial position or results of operations as a result of nonperformance by counterparties. For more information on derivative instruments, see Note 5.

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. For more information on asset retirement obligations, see Note 8.

Natural gas costs recoverable or refundable through rate adjustments
Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within a period ranging from 24 to 28 months from the time such costs are paid. Natural gas costs recoverable through rate adjustments amounted to $691,000 and $15.5 million at December 31, 2005 and 2004, 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 $750,000 per occurrence. Automobile liability and general liability losses are insured, subject to deductibles ranging up to $500,000 per accident or occurrence. These subsidiaries have excess coverage above the primary automobile and general liability policies on a claims first-made basis beyond the deductible levels. The subsidiaries of the Company are retaining losses up to the deductible amounts accrued on the basis of estimates of liability for claims incurred and for claims incurred but not reported.

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

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

Foreign currency translation adjustment
The functional currency of the Company's investment in a 220-MW natural gas-fired electric

generating facility in Brazil, as further discussed in Note 2, was the Brazilian Real. Translation from the Brazilian Real to the U.S. dollar for assets and liabilities was performed using the exchange rate in effect at the balance sheet date. Revenues and expenses had been translated using the weighted average exchange rate for each month prevailing during the period reported. Adjustments resulting from such translations were 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 were recorded in income.

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

Earnings per common share
Basic earnings per common share were computed by dividing earnings on common stock by the weighted average number of shares of common stock outstanding during the year. Diluted earnings per common share were computed by dividing earnings on common stock by the total of the weighted average number of shares of common stock outstanding during the year, plus the effect of outstanding stock options, restricted stock grants and performance share awards. For the years ended December 31, 2004 and 2003, 36,000 shares and 209,805 shares, respectively, with an average exercise price of $25.70 and $24.56, respectively, attributable to the exercise of outstanding options, were excluded from the calculation of diluted earnings per share because their effect was antidilutive. In 2005, there were no shares excluded from the calculation of diluted earnings per share. Common stock outstanding includes issued shares less shares held in treasury.

Stock-based compensation
The Company has stock option plans for directors, key employees and employees. In 2003, the Company adopted the fair value recognition provisions of SFAS No. 123 and began expensing the fair market value of stock options for all awards granted on or after January 1, 2003. Compensation expense recognized for awards granted on or after January 1, 2003, for the years ended December 31, 2005, 2004 and 2003, was $2,000, $18,000 and $41,000 respectively (after tax).

As permitted by SFAS No. 148, the Company accounts for stock options granted prior to January 1, 2003, under APB Opinion No. 25. No compensation expense has been recognized for stock options granted prior to January 1, 2003, as the options granted had an exercise price equal to the market value of the underlying common stock on the date of the grant.

The Company adopted SFAS No. 123 effective January 1, 2003, for newly granted options only. The following table illustrates the effect on earnings and earnings per common share for the years ended December 31, 2005, 2004 and 2003, as if the Company had applied SFAS No. 123 and recognized compensation expense for all outstanding and unvested stock options based on the fair value at the date of grant:

	2005	2004	2003
	(In thousands, except per share amounts)		
Earnings on common stock, as reported	$274,398	$206,382	$174,607
Stock-based compensation expense included in reported earnings, net of related tax effects	2	18	41
Total stock-based compensation expense determined under fair value method for all awards, net of related tax effects	(471)	(62)	(2,139)
Pro forma earnings on common stock	$273,929	$206,338	$172,509

Earnings per common share - basic - as reported:			
Earnings before cumulative effect of accounting change	$ 2.31	$ 1.77	$ 1.64
Cumulative effect of accounting change	---	---	(.07)
Earnings per common share - basic	$ 2.31	$ 1.77	$ 1.57
Earnings per common share - basic - pro forma:			
Earnings before cumulative effect of accounting change	$ 2.30	$ 1.77	$ 1.62
Cumulative effect of accounting change	---	---	(.07)
Earnings per common share - basic	$ 2.30	$ 1.77	$ 1.55
Earnings per common share - diluted - as reported:			
Earnings before cumulative effect of accounting change	$ 2.29	$ 1.76	$ 1.62
Cumulative effect of accounting change	---	---	(.07)
Earnings per common share - diluted	$ 2.29	$ 1.76	$ 1.55
Earnings per common share - diluted - pro forma:			
Earnings before cumulative effect of accounting change	$ 2.29	$ 1.76	$ 1.60
Cumulative effect of accounting change	---	---	(.07)
Earnings per common share - diluted	$ 2.29	$ 1.76	$ 1.53

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

Use of estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements, 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; 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,	2005	2004	2003
	(In thousands)		
Interest, net of amount capitalized	$47,902	$50,236	$47,474
Income taxes	$106,771	$50,487	$31,737

New accounting standards

SAB No. 106 In September 2004, the SEC issued SAB No. 106, which is an interpretation regarding the application of SFAS No. 143 by oil and gas producing companies following the full-cost accounting method. SAB No. 106 clarifies that the future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet should be excluded from the computation of the present value of estimated future net revenues for purposes of the full-cost ceiling calculation. SAB No. 106 also states that a company is expected to disclose in the financial statement footnotes and MD&A how the company's calculation of the ceiling test and depreciation, depletion and amortization are affected by the adoption of SFAS No. 143. SAB No. 106 was effective for the Company as of January 1, 2005. The adoption of SAB No. 106 did not have a material effect on the Company's financial position or results of operations. The effects of the adoption of SFAS No. 143 and SAB No. 106 as they relate to the Company's natural gas and oil production properties are described below.

Ceiling Test Calculation
As discussed in this note, the Company's natural gas and oil production properties are subject to a "ceiling test" that limits capitalized costs to the aggregate of the present value of future net revenues of proved reserves based on single point-in-time spot market prices, as mandated under the rules of the SEC, and the cost of unproved properties. Prior to the adoption of SFAS No. 143, the Company calculated the full-cost ceiling by reducing its expected future revenues from proved natural gas and oil reserves by the estimated future expenditures to be incurred in developing and producing such reserves, including future retirements, discounted using a factor mandated by the rules of the SEC. While expected future cash flows related to the asset retirement obligations were included in the calculation of the ceiling test, no associated asset retirement obligation was recognized on the balance sheet.

Upon the adoption of SFAS No. 143 but prior to the effective date of SAB No. 106, the Company continued to calculate the full-cost ceiling as previously described. In addition, the Company recorded the fair value of a liability for the asset retirement obligation and capitalized the cost by increasing the carrying amount of the related long-lived asset.

Upon the adoption of SAB No. 106, the future capitalized discounted cash outflows associated with settling asset retirement obligations that are accrued on the consolidated balance sheet are excluded from the computation of the present value of estimated future net revenues for purposes of the full-cost ceiling calculation in accordance with SAB No. 106.

Depreciation, Depletion and Amortization
Costs subject to amortization include: (A) all capitalized costs, less accumulated amortization, other than the cost of acquiring and evaluating unproved property; (B) the estimated future expenditures (based on current costs) to be incurred in developing proved reserves; and (C) estimated dismantlement and abandonment costs, net of estimated salvage values.

Subsequent to the adoption of SFAS No. 143, the estimated future dismantlement and abandonment costs described in (C) above are included in the capitalized costs described in (A) above at the expected future cost discounted to the present value, to the extent that a legal obligation exists. Under SFAS No. 143, the recognition of the asset retirement obligation does not take into account estimated salvage values. The liability associated with the recognition of an asset retirement obligation is accreted over time with accretion expense recorded in depreciation, depletion and amortization expense on the Consolidated Statements of Income. The Company's estimated dismantlement and abandonment costs as described in (C) above were adjusted to account for asset retirement obligations accrued on the Consolidated Balance Sheets when calculating the depreciation, depletion and amortization rates. In addition, estimated salvage values were included in the Company's depreciation, depletion and amortization calculation. The Company's estimate of future dismantlement and abandonment costs that will be incurred as a result of future development activities on proved reserves continues to be included in the calculation of costs to be amortized.

Any gains or losses on the settlement of an asset retirement obligation, if applicable, are treated as adjustments to the capitalized costs, consistent with the full-cost accounting method.

SFAS No. 123 (revised) In December 2004, the FASB issued SFAS No. 123 (revised). This accounting standard revises SFAS No. 123 and requires entities to recognize compensation expense in an amount equal to the grant-date fair value of share-based payments granted to employees. SFAS No. 123 (revised) is effective for the Company on January 1, 2006. As of the required effective date, the Company will apply SFAS No. 123 (revised) using the modified prospective method, recognizing compensation expense for all awards granted after the date of adoption of SFAS No. 123 (revised) and for the unvested portion of previously granted awards that remain outstanding at the date of adoption. The Company used the Black-Scholes option-pricing model to calculate the fair value of stock options. The Company estimates the adoption of SFAS No. 123 (revised) will result in less than $300,000 (after tax) in additional stock-based compensation expense for the year ended December 31, 2006.

FIN 47 In March 2005, the FASB issued FIN 47. FIN 47 addresses the diverse accounting practices that developed with respect to the timing of liability recognition for legal obligations associated with the retirement of a tangible long-lived asset when the timing and/or method of settlement of the obligation are conditional on a future event. FIN 47 concludes that an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation when incurred if the liability's fair value can be reasonably estimated. FIN 47 is effective for the Company at the end of the fiscal year ending December 31, 2005. The adoption of FIN 47 did not have a material effect on the Company's financial position or results of operations.

EITF No. 04-6 In March 2005, the FASB ratified EITF No. 04-6. EITF No. 04-6 requires that post-production stripping costs be treated as a variable inventory production cost. As a result, such costs will be subject to inventory costing procedures in the period they are incurred. EITF No. 04-6 is effective for the Company on January 1, 2006. The adoption of EITF No. 04-6 is not expected to have a material effect on the Company's financial position or results of operations.

Comprehensive income

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

The components of other comprehensive income (loss), and their related tax effects for the years ended December 31, 2005, 2004 and 2003, were as follows:

	2005	2004	2003
		(In thousands)	
Other comprehensive income (loss):			
Net unrealized gain (loss) on derivative instruments qualifying as hedges:			
Net unrealized loss on derivative instruments arising during the period, net of tax of $16,391, $2,734 and $2,132 in 2005, 2004 and 2003, respectively	$(26,167)	$(4,367)	$ (3,335)
Less: Reclassification adjustment for loss on derivative instruments included in net income, net of tax of $2,734, $2,132 and			

$2,903 in 2005, 2004 and 2003, respectively	(4,367)	(3,335)	(4,541)
Net unrealized gain (loss) on derivative instruments qualifying as hedges	(21,800)	(1,032)	1,206
Minimum pension liability adjustment, net of tax of $353, $2,406 and $38 in 2005, 2004 and 2003, respectively	574	(3,782)	21
Foreign currency translation adjustment	(1,099)	852	1,048
Total other comprehensive income (loss)	$(22,325)	$(3,962)	$ 2,275

The after-tax components of accumulated other comprehensive loss as of December 31, 2005, 2004 and 2003, were as follows:

	Net Unrealized Loss on Derivative Instruments Qualifying as Hedges	Minimum Pension Liability Adjustment	Foreign Currency Translation Adjustment	Total Accumulated Other Comprehensive Loss
	(In thousands)			
Balance at December 31, 2003	$ (3,335)	$(4,443)	$ 249	$ (7,529)
Balance at December 31, 2004	$ (4,367)	$(8,225)	$1,101	$(11,491)
Balance at December 31, 2005	$(26,167)	$(7,651)	$ 2	$(33,816)

NOTE 2 - EQUITY METHOD INVESTMENTS

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

In February 2004, Centennial International acquired 49.99 percent of Carib Power. Carib Power, through a wholly owned subsidiary, owns a 225-MW natural gas-fired electric generating facility in Trinidad and Tobago. The Trinity Generating Facility sells its output to the T&TEC, the governmental entity responsible for the transmission, distribution and administration of electrical power to the national electrical grid of Trinidad and Tobago. The power purchase agreement expires in September 2029. T&TEC also is under contract to supply natural gas to the Trinity Generating Facility during the term of the power purchase agreement. The functional currency for the Trinity Generating Facility is the U.S. dollar.

In September 2004, Centennial Resources, through indirect wholly owned subsidiaries, acquired a 50-percent ownership interest in Hartwell, which owns a 310-MW natural gas-fired electric generating facility near Hartwell, Georgia. The Hartwell Generating Facility sells its output under a power purchase agreement with Oglethorpe that expires in May 2019. Oglethorpe reimburses the Hartwell Generating Facility for actual costs of fuel required to operate the plant. American National Power, a wholly owned subsidiary of International Power of the United Kingdom, holds the remaining 50-percent ownership interest and is the operating partner for the facility.

In June 2005, the Company completed the sale of its 49 percent interest in MPX to Petrobras, the Brazilian state-controlled energy company. The Company realized a gain of $15.6 million from the sale in the second quarter of 2005. MPX owns and operates the Termoceara Generating Facility in the Brazilian state of Ceara. Petrobras had entered into a contract to purchase all of the capacity and market all of the energy from the

Termoceara Generating Facility. The electric power sales contract with Petrobras was scheduled to expire in mid-2008.

The functional currency for the Termoceara Generating Facility was the Brazilian Real. The electric power sales contract with Petrobras contained an embedded derivative, which derived its value from an annual adjustment factor, which largely indexed the contract capacity payments to the U.S. dollar. The Company's 49 percent share of the gain from the change in fair value of the embedded derivative in the electric power sales contract for the year ended December 31, 2004, was $2.5 million (after tax). The Company's 49 percent share of the loss from the change in fair value of the embedded derivative in the electric power sales contract for the year ended December 31, 2003, was $11.3 million (after tax). The Company's 49 percent share of the foreign currency gain resulting from an increase in value of the Brazilian Real versus the U.S. dollar for the years ended December 31, 2004 and 2003, was $1.9 million (after tax) and $2.8 million (after tax), respectively.

In 2005, the Termoceara Generating Facility was accounted for as an asset held for sale and, as a result, no depreciation, depletion and amortization expense was recorded in 2005.

At December 31, 2005, the Company's equity method investments, including Carib Power and Hartwell, had total assets of $231.9 million and long-term debt of $154.8 million. At December 31, 2004, the Company's equity method investments, including MPX, Carib Power and Hartwell, had total assets of $334.2 million and long-term debt of $224.9 million. The Company's investment in its equity method investments, including the Trinity and Hartwell Generating Facilities, was approximately $41.8 million, including undistributed earnings of $3.5 million, at December 31, 2005. The Company's investment in the Termoceara, Trinity and Hartwell Generating Facilities was approximately $65.7 million, including undistributed earnings of $26.6 million, at December 31, 2004.

NOTE 3 - GOODWILL AND OTHER INTANGIBLE ASSETS

The changes in the carrying amount of goodwill for the year ended December 31, 2005, were as follows:

	Balance as of January 1, 2005	Goodwill Acquired During the Year*	Balance as of December 31, 2005
		(In thousands)	
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Construction services	62,632	18,338	80,970
Pipeline and energy services	5,464	---	5,464
Natural gas and oil production	---	---	---
Construction materials and mining	120,452	12,812	133,264
Independent power production	11,195	(28)	11,167
Other	---	---	---
Total	$199,743	$31,122	$ 230,865

* *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, 2004, were as follows:

	Balance as of January 1, 2004	Goodwill Acquired During the Year*	Goodwill Impaired During the Year	Balance as of December 31, 2004
		(In thousands)		

Electric	$ ---	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---	---
Construction services	62,604	28	---	62,632
Pipeline and energy services	9,494	---	(4,030)	5,464
Natural gas and oil production	---	---	---	---
Construction materials and mining	120,198	254	---	120,452
Independent power production	7,131	4,064	---	11,195
Other	---	---	---	---
Total	$ 199,427	$ 4,346	$(4,030)	$199,743

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

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

Other intangible assets at December 31, 2005 and 2004, were as follows:

	2005	2004
	(In thousands)	
Amortizable intangible assets:		
Acquired contracts	$18,065	$15,041
Accumulated amortization	(9,458)	(5,013)
	8,607	10,028
Noncompete agreements	11,784	10,575
Accumulated amortization	(8,557)	(8,186)
	3,227	2,389
Other	7,914	9,535
Accumulated amortization	(1,213)	(534)
	6,701	9,001
Unamortizable intangible assets	524	851
Total	$19,059	$22,269

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

Amortization expense for amortizable intangible assets for the years ended December 31, 2005, 2004 and 2003, was $5.5 million, $3.8 million and $2.2 million, respectively. Estimated amortization expense for amortizable intangible assets is $3.5 million in 2006,

$2.7 million in 2007, $2.6 million in 2008, $2.6 million in 2009, $2.2 million in 2010 and $4.9 million thereafter.

NOTE 4 - REGULATORY ASSETS AND LIABILITIES

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

	2005	2004
	(In thousands)	
Regulatory assets:		
Deferred income taxes	$ 38,757	$ 39,212
Plant costs	13,122	12,838
Long-term debt refinancing costs	3,160	3,531
Natural gas costs recoverable through rate adjustments	691	15,534
Other	6,519	7,732
Total regulatory assets	62,249	78,847
Regulatory liabilities:		
Plant removal and decommissioning costs	78,280	78,525
Taxes refundable to customers	14,966	15,660
Deferred income taxes	10,298	15,192
Liabilities for regulatory matters	7,405	18,853
Other	4,830	3,676
Total regulatory liabilities	115,779	131,906
Net regulatory position	$ (53,530)	$(53,059)

As of December 31, 2005, a large portion of the Company's regulatory assets, other than certain deferred income taxes, was being reflected in rates charged to customers and is being recovered over the next one to 17 years.

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

NOTE 5 - DERIVATIVE INSTRUMENTS

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

In the event a derivative instrument being accounted for as a cash flow hedge does not qualify for hedge accounting because it is no longer highly effective in offsetting changes in cash flows of a hedged item; if the derivative instrument expires or is sold, terminated or exercised; 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, 2005, Fidelity held derivative instruments designated as cash flow hedging instruments.

Hedging activities

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

The fair value of the hedging instruments must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or liability. Changes in the fair value attributable to the effective portion of hedging instruments, net of tax, are recorded in stockholders' equity as a component of accumulated other comprehensive income (loss). At the date the natural gas or oil production 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. Based on the recent rise in market prices of natural gas and oil, the fair value of the Company's derivative liability has increased significantly since December 31, 2004. The proceeds the Company receives for its natural gas and oil production are also generally based on market prices.

For the years ended December 31, 2005, 2004 and 2003, the amount of hedge ineffectiveness, which was included in operating revenues, was immaterial. For the years ended December 31, 2005, 2004 and 2003, Fidelity did not exclude any components of the derivative instruments' gain or loss from the assessment of hedge effectiveness and there were no reclassifications into earnings as a result of the discontinuance of hedges.

Gains and losses on derivative instruments that are reclassified from accumulated other comprehensive income (loss) to current-period earnings are included in the line item in which the hedged item is recorded. As of December 31, 2005, the maximum term of Fidelity's swap and collar agreements, in which Fidelity is hedging its exposure to the variability in future cash flows for forecasted transactions, is 12 months. The Company estimates that over the next 12 months, net losses of approximately $25.8 million will be reclassified from accumulated other comprehensive loss into earnings, subject to changes in natural gas and oil market prices, as the hedged transactions affect earnings.

NOTE 6 - FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS

The estimated fair value of the Company's long-term debt is based on quoted market prices of the same or similar issues. The estimated fair values of the Company's natural gas and oil price swap and collar agreements were included in current liabilities at December 31, 2005 and 2004. The estimated fair values of the Company's natural gas and oil price swap and collar agreements reflect the estimated amounts the Company would receive or pay to terminate the contracts at the reporting date based upon quoted market prices of comparable contracts.

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

	2005 Carrying Amount	2005 Fair Value	2004 Carrying Amount	2004 Fair Value
	(In thousands)			
Long-term debt	$ 1,206,510	$1,219,347	$945,487	$992,172
Natural gas and oil price swap and collar agreement obligations	$ 42,011	$ 42,011	$ 7,101	$ 7,101

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

NOTE 7 - LONG-TERM DEBT AND INDENTURE PROVISIONS

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

	2005	2004
	(In thousands)	
First mortgage bonds and notes:		
Pollution Control Refunding Revenue Bonds, Series 1992, 6.65%, redeemed in 2005	$ ---	$ 20,850
Secured Medium-Term Notes, Series A, at a weighted average rate of 7.75%, due on dates ranging from April 1, 2007 to April 1, 2012	95,000	95,000
Senior Notes, 5.98%, due December 15, 2033	30,000	30,000
Total first mortgage bonds and notes	125,000	145,850
Senior notes at a weighted average rate of 5.83%, due on dates ranging from May 31, 2006 to July 1, 2019	815,000	728,500
Commercial paper at a weighted average rate of 4.33%, supported by revolving credit agreements	260,000	63,000
Term credit agreements at a weighted average rate of 6.60%, due on dates ranging from March 31, 2006 to December 1, 2013	6,623	8,172
Discount	(113)	(35)
Total long-term debt	1,206,510	945,487
Less current maturities	101,758	72,046
Net long-term debt	$1,104,752	$ 873,441

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2005, aggregate $101.8 million in 2006; $106.9 million in 2007; $161.3 million in 2008; $86.9 million in 2009; $266.8 million in 2010 and $482.8 million thereafter.

Certain debt instruments of the Company and its subsidiaries, including those discussed below, contain restrictive covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2005.

MDU Resources Group, Inc.

The Company has a revolving credit agreement with various banks totaling $100 million (with provision for an increase, at the option of the Company on stated conditions, up to a maximum of $125 million). There were no amounts outstanding under the credit agreement at December 31, 2005 and 2004. The credit agreement supports the Company's $100 million (previously $75 million) commercial paper program. Under the Company's commercial paper program, $60.0 million and $37.0 million were outstanding at December 31, 2005 and 2004, respectively, which was classified as long-term debt. The commercial paper borrowings are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings (supported by the credit agreement, which expires in June 2010).

In order to borrow under the Company's credit agreement, the Company must be in compliance with the applicable covenants and certain other conditions, including covenants not to permit, as of the end of any fiscal quarter, (A) the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent or (B) the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Also included is a covenant that does not permit the ratio of the Company's earnings before interest, taxes, depreciation and amortization to interest expense (determined with respect to the Company alone, excluding its subsidiaries), for the 12-month period ended each fiscal quarter, to be less than 2.5 to 1. Other covenants include restrictions on the sale of certain assets and on the making of certain investments. The Company was in compliance with these covenants and met the required conditions at December 31, 2005. In the event the Company does not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued, as previously described.

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

The Company's issuance of first mortgage debt is subject to certain restrictions imposed under the terms and conditions of its Indenture of Mortgage. Generally, those restrictions require the Company to fund $1.43 of unfunded property or use $1.00 of refunded bonds for each dollar of indebtedness incurred under the Indenture and, in some cases, to certify to the trustee that annual earnings (pretax and before interest charges), as defined in the Indenture, equal at least two times its annualized first mortgage bond interest costs. Under the more restrictive of the tests, as of December 31, 2005, the Company could have issued approximately $364 million of additional first mortgage bonds.

Approximately $430.7 million in net book value of the Company's net electric and natural gas distribution properties at December 31, 2005, with certain exceptions, are subject to the lien of the Indenture of Mortgage dated May 1, 1939, as supplemented, amended and restated, from the Company to The Bank of New York and Douglas J. MacInnes, successor trustee, and are subject to the junior lien of the Indenture dated as of December 15, 2003, as supplemented, from the Company to The Bank of New York, as trustee.

Centennial Energy Holdings, Inc.
Centennial has three revolving credit agreements with various banks and institutions totaling $441.4 million with certain provisions allowing for increased borrowings. These credit agreements support Centennial's $350 million commercial paper program. There were no outstanding borrowings under the Centennial credit agreements at December 31, 2005 or 2004. Under the Centennial commercial paper program, $200.0 million and $26.0 million were outstanding at December 31, 2005 and 2004, respectively. The Centennial commercial paper borrowings are classified as long-term debt as Centennial intends to refinance these borrowings on a long-term basis through continued Centennial commercial paper borrowings (supported by Centennial credit agreements). One of these credit agreements is for $400 million, which includes a provision for an increase, at the option of Centennial on stated conditions, up to a maximum of $450 million and expires on August 26, 2010. Another agreement is for $21.4 million and expires on April 30, 2007. Pursuant to this credit agreement, on the last business day of April 2006, the line of credit will be reduced by $3.6 million. Centennial intends to negotiate the extension or replacement of these agreements prior to their maturities. The third agreement is an uncommitted line for $20 million, which was effective on January 27, 2006, and may be terminated by the bank at any time. As of December 31, 2005, $32.3 million of letters of credit were outstanding, as discussed in Note 18, of which $14.9 million were outstanding under the above credit agreements that reduced amounts available under these agreements.

Centennial has an uncommitted long-term master shelf agreement that allows for borrowings of up to $450 million. Under the terms of the master shelf agreement, $447.5 million and

$384.0 million were outstanding at December 31, 2005 and 2004, respectively. The ability to request additional borrowings under this master shelf agreement expires in April 2008. To meet potential future financing needs, Centennial may pursue other financing arrangements, including private and/or public financing.

In order to borrow under Centennial's credit agreements and the Centennial uncommitted long-term master shelf agreement, Centennial and certain of its subsidiaries must be in compliance with the applicable covenants and certain other conditions, including covenants not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 65 percent (for the $400 million credit agreement) and 60 percent (for the $21.4 million credit agreement and the master shelf agreement). 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, for the 12-month period ended each fiscal quarter, to be less than 2.5 to 1 (for the $400 million credit agreement), 2.25 to 1 (for the $21.4 million credit agreement) and 1.75 to 1 (for the master shelf agreement). Other covenants include minimum consolidated net worth, limitation on priority debt and restrictions on the sale of certain assets and on the making of certain loans and investments. Centennial and such subsidiaries were in compliance with these covenants and met the required conditions at December 31, 2005. In the event Centennial or such subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued as previously described.

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

Williston Basin Interstate Pipeline Company
Williston Basin has an uncommitted long-term master shelf agreement that allows for borrowings of up to $100 million. Under the terms of the master shelf agreement, $55.0 million was outstanding at December 31, 2005 and 2004. The ability to request additional borrowings under this master shelf agreement expires on December 20, 2007.

In order to borrow under its uncommitted long-term master shelf agreement, Williston Basin must be in compliance with the applicable covenants and certain other conditions, including covenants not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 55 percent. Other covenants include limitation on priority debt and some restrictions on the sale of certain assets and the making of certain investments. Williston Basin was in compliance with these covenants and met the required conditions at December 31, 2005. In the event Williston Basin does not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

NOTE 8 - ASSET RETIREMENT OBLIGATIONS
The Company adopted SFAS No. 143 on January 1, 2003. The Company recorded obligations related to the plugging and abandonment of natural gas and oil wells, decommissioning of certain electric generating facilities, reclamation of certain aggregate properties and certain other obligations associated with leased properties. Upon adoption of SFAS No. 143, the Company recorded an additional discounted liability of $22.5 million and a regulatory asset of $493,000, increased net property, plant and equipment by $9.6 million and recognized a one-time cumulative effect charge of $7.6 million (net of deferred income tax benefits of $4.8 million).

The Company adopted FIN 47 on December 31, 2005, as discussed in Note 1. The Company recorded obligations related to special handling and disposal of hazardous materials at certain electric generating and distribution facilities, natural gas distribution and transmission facilities, and buildings. Upon adoption of FIN 47, the Company recorded an additional discounted liability of $1.7 million and a regulatory asset of $1.5 million and increased net property, plant and equipment by $151,000. There was no impact on net income; therefore pro forma presentation amounts assuming retroactive application of the accounting change on net income are not necessary.

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

	2005	2004
	(In thousands)	
Balance at beginning of year	$ 37,350	$ 34,633
Liabilities incurred	3,786	3,718
Liabilities acquired	1,138	178
Liabilities settled	(3,328)	(2,286)
Accretion expense	2,241	1,931
Revisions in estimates	740	(824)
Liabilities recorded upon adoption of FIN 47	1,663	---
Other	47	---
Balance at end of year	$ 43,637	$ 37,350

The following reconciliation of the Company's liability for the years ended December 31 includes the pro forma effects of the adoption of FIN 47 for all years presented.

	2005	2004
	(In thousands)	
Balance at beginning of year	$ 38,924	$ 36,122
Liabilities incurred	3,786	3,718
Liabilities acquired	1,138	178
Liabilities settled	(3,328)	(2,286)
Accretion expense	2,241	1,931
Revisions in estimates	740	(824)
Other	136	85
Balance at end of year	$ 43,637	$ 38,924

The Company believes that any expenses under SFAS No. 143 and FIN 47 as they relate to regulated operations will be recovered in rates over time and, accordingly, deferred such expenses as a regulatory asset upon adoption. The Company will continue to defer those expenses that it believes will be recovered in rates over time.

The fair value of assets that are legally restricted for purposes of settling asset retirement obligations at December 31, 2005 and 2004, was $5.1 million and $5.2 million, respectively.

NOTE 9 - PREFERRED STOCKS

Preferred stocks at December 31 were as follows:

	2005	2004
	(Dollars in thousands)	
Authorized:		
Preferred -		
500,000 shares, cumulative, par value $100, issuable in series		
Preferred stock A -		
1,000,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Preference -		
500,000 shares, cumulative, without par value, issuable in series (none outstanding)		

Outstanding:		
4.50% Series - 100,000 shares	$10,000	$10,000
4.70% Series - 50,000 shares	5,000	5,000
Total preferred stocks	$15,000	$15,000

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

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

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

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

NOTE 10 - COMMON STOCK

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

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

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. Since January 1, 2003, the Stock Purchase Plan and K-Plan, with respect to Company stock, have been funded by the purchase of shares of common stock on the open market. At December 31, 2005, there were 12.1 million shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan.

NOTE 11 - STOCK-BASED COMPENSATION

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

For a discussion of the adoption of SFAS No. 123 and the effect on earnings and earnings per common share for the years ended December 31, 2005, 2004 and 2003, as if the Company had applied SFAS No. 123 and recognized compensation expense for all outstanding and unvested stock options based on the fair value at the date of grant, see Note 1.

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

A summary of the status of the stock option plans at December 31, 2005, 2004 and 2003, and changes during the years then ended were as follows:

	2005		2004		2003	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Balance at beginning of year	2,561,684	$19.29	4,182,456	$19.09	4,861,268	$18.58
Granted	---	---	---	---	27,015	17.29
Forfeited	(114,552)	20.30	(382,942)	19.64	(188,486)	20.05
Exercised	(589,150)	18.48	(1,237,830)	18.49	(517,341)	13.88
Balance at end of year	1,857,982	19.48	2,561,684	19.29	4,182,456	19.09
Exercisable at end of year	1,093,523	$18.86	1,700,223	$18.73	611,404	$15.06

Summarized information about stock options outstanding and exercisable as of December 31, 2005, was as follows:

	Options Outstanding			Options Exercisable	
Range of Exercisable Prices	Number Outstanding	Remaining Contractual Life in Years	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$ 8.22 - 13.00	10,125	1.5	$10.92	10,125	$10.92
13.01 - 17.00	234,535	2.5	14.39	231,889	14.38
17.01 - 21.00	1,438,992	5.2	19.76	785,874	19.78
21.01 - 25.70	174,330	5.2	24.51	65,635	24.87

Balance at end of year	1,857,982	4.8	19.48	1,093,523	18.86

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

	2005	2004	2003
Weighted average fair value of options at grant date	---	---	$4.67
Weighted average risk-free interest rate	---	---	3.91%
Weighted average expected price volatility	---	---	32.28%
Weighted average expected dividend yield	---	---	3.43%
Expected life in years	---	---	7

In addition, prior to 2002 the Company granted restricted stock awards under a long-term incentive plan and deferred compensation agreements. The restricted stock awards granted vest to the participants at various times ranging from one year to nine years from date of issuance, but certain grants may vest early based upon the attainment of certain performance goals or upon a change in control of the Company. The Company also has granted stock awards totaling 28,586 shares, 35,205 shares and 31,855 shares in 2005, 2004 and 2003, respectively, under a nonemployee director stock compensation plan. The weighted average grant date fair value of the stock grants was $28.32, $23.61 and $21.40 in 2005, 2004 and 2003, respectively. Nonemployee directors may receive shares of common stock instead of cash in payment for directors' fees under the nonemployee director stock compensation plan. Compensation expense recognized for restricted stock grants and stock grants was $1.8 million, $3.4 million and $4.8 million in 2005, 2004 and 2003, respectively.

In 2005, 2004 and 2003, key employees of the Company were awarded performance share awards. Entitlement to performance shares is based on the Company's total shareholder return over designated performance periods as measured against a selected peer group. Target grants of performance shares were made for the following performance periods:

Grant Date	Performance Period	Target Grant of Shares
February 2003	2003-2005	54,180
February 2004	2004-2006	185,743
February 2005	2005-2007	182,927

Participants may earn additional performance shares if the Company's total shareholder return exceeds that of the selected peer group. The final value of the performance units may vary according to the number of shares of Company stock that are ultimately granted based on the performance criteria. Compensation expense recognized for the performance share awards for the years ended December 31, 2005, 2004 and 2003, was $3.6 million, $2.5 million and $879,000, respectively.

The Company is authorized to grant options, restricted stock and stock for up to 12.7 million shares of common stock and has granted options, restricted stock and stock on 5.8 million shares through December 31, 2005.

NOTE 12 - INCOME TAXES

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

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) X An Original (2) _ A Resubmission	12/31/2005	2005/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

	2005	2004	2003
	(In thousands)		
United States	$407,118	$280,764	$278,143
Foreign	13,744	20,277	3,342
Income before income taxes	$420,862	$301,041	$281,485

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

	2005	2004	2003
	(In thousands)		
Current:			
Federal	$ 95,153	$47,625	$26,313
State	20,575	12,231	7,408
Foreign	(189)	955	264
	$115,539	60,811	33,985
Deferred:			
Income taxes -			
Federal	25,726	28,556	55,660
State	5,014	5,422	9,861
Foreign	---	(223)	(338)
Investment tax credit	(500)	(592)	(596)
	30,240	33,163	64,587
Total income tax expense	$145,779	$93,974	$98,572

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

	2005	2004
	(In thousands)	
Deferred tax assets:		
Regulatory matters	$ 38,757	$ 39,212
Accrued pension costs	22,000	18,754
Natural gas and oil price swap and collar agreements	16,375	2,734
Deferred compensation	13,057	9,938
Asset retirement obligations	13,017	12,197
Bad debts	2,804	2,266
Deferred investment tax credit	530	724
Other	31,288	26,503
Total deferred tax assets	137,828	112,328
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	465,637	450,237
Basis differences on natural gas and oil producing properties	159,077	124,788
Regulatory matters	10,298	15,192
Other	19,930	13,826
Total deferred tax liabilities	654,942	604,043
Net deferred income tax liability	$(517,114)	$(491,715)

As of December 31, 2005 and 2004, no valuation allowance has been recorded associated with the above deferred tax assets.

The following table reconciles the change in the net deferred income tax liability from December 31, 2004, to December 31, 2005, to deferred income tax expense:

	2005
	(In thousands)
Change in net deferred income tax liability from the preceding table	$25,399
Deferred taxes associated with other comprehensive income	13,304
Deferred taxes associated with acquisitions	(6,825)
Other	(1,638)
Deferred income tax expense for the period	$30,240

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

Years ended December 31,	2005		2004		2003	
	Amount	%	Amount	%	Amount	%
			(Dollars in thousands)			
Computed tax at federal statutory rate	$ 147,302	35.0	$105,364	35.0	$98,520	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax benefit	15,459	3.7	11,468	3.8	11,857	4.2
Depletion allowance	(4,381)	(1.1)	(3,418)	(1.2)	(3,117)	(1.1)
Foreign operations	(4,209)	(1.0)	(5,648)	(1.9)	(832)	(.3)
Renewable electricity production credit	(4,087)	(1.0)	(3,404)	(1.1)	(3,395)	(1.2)
Audit resolution	---	---	(8,818)	(2.9)	---	---
Other items	(4,305)	(1.0)	(1,570)	(.5)	(4,461)	(1.6)
Total income tax expense	$ 145,779	34.6	$93,974	31.2	$98,572	35.0

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

The Company considers earnings (including the gain from the sale of its foreign equity method investment in a natural gas-fired electric generating facility in Brazil) to be reinvested indefinitely outside of the United States and, accordingly, no U.S. deferred income taxes are recorded with respect to such earnings. Should the earnings be remitted as dividends, the Company may be subject to additional U.S. taxes, net of allowable foreign tax credits. The cumulative undistributed earnings at December 31, 2005, were approximately $36 million. The amount of unrecognized deferred tax liability associated with the undistributed earnings was approximately $9.5 million.

NOTE 13 - BUSINESS SEGMENT DATA

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. The vast majority of the Company's operations are located within the United States. The Company also has investments in foreign countries, which largely consist of investments in natural resource-based projects.

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

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) X An Original (2) _ A Resubmission	12/31/2005	2005/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

The construction services segment specializes in electrical line construction, pipeline construction, inside electrical wiring and cabling and the manufacture and distribution of specialty equipment.

The pipeline and energy services segment provides natural gas transportation, underground storage and gathering services through regulated and nonregulated pipeline systems primarily in the Rocky Mountain and northern Great Plains regions of the United States. The pipeline and energy services segment also provides energy-related management services, including cable and pipeline magnetization and locating.

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

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

The independent power production segment owns, builds and operates electric generating facilities in the United States and has investments in domestic and international natural resource-based projects. Electric capacity and energy produced at its power plants primarily are sold under mid-and long-term contracts to nonaffiliated entities.

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

	2005	2004	2003
	(In thousands)		
External operating revenues:			
Electric	$ 181,238	$ 178,803	$ 178,562
Natural gas distribution	384,199	316,120	274,608
Pipeline and energy services	387,870	281,913	187,892
	953,307	776,836	641,062
Construction services	686,734	425,250	434,177
Natural gas and oil production	163,539	152,486	140,281
Construction materials and mining	1,603,326	1,321,626	1,104,408
Independent power production	48,508	43,059	32,261
Other	---	---	---
	2,502,107	1,942,421	1,711,127
Total external operating revenues	$ 3,455,414	$2,719,257	$2,352,189
Intersegment operating revenues:			
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Construction services	391	1,571	---
Pipeline and energy services	92,424	75,316	64,300
Natural gas and oil production	275,828	190,354	124,077
Construction materials and mining	1,284	535	---
Independent power production	---	---	---
Other	6,038	4,423	2,728
Intersegment eliminations	(375,965)	(272,199)	(191,105)
Total intersegment operating revenues	$ ---	$ ---	$ ---

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) X An Original (2) __ A Resubmission	12/31/2005	2005/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Depreciation, depletion and amortization:			
Electric	$ 20,818	$ 20,199	$ 20,150
Natural gas distribution	9,534	9,329	10,044
Construction services	13,459	11,113	10,353
Pipeline and energy services	12,784	17,804	15,016
Natural gas and oil production	84,754	70,823	61,019
Construction materials and mining	77,988	69,644	63,601
Independent power production	8,990	9,587	7,860
Other	330	271	294
Total depreciation, depletion and amortization	$ 228,657	$ 208,770	$ 188,337
Interest expense:			
Electric	$ 7,553	$ 9,116	$ 8,013
Natural gas distribution	3,973	4,292	3,936
Construction services	4,177	3,442	3,668
Pipeline and energy services	8,498	9,262	7,952
Natural gas and oil production	7,550	7,552	4,767
Construction materials and mining	21,365	20,646	18,747
Independent power production	2,260	4,354	5,850
Other	(399)	(70)	15
Intersegment eliminations	(227)	(1,157)	(154)
Total interest expense	$ 54,750	$ 57,437	$ 52,794
Income taxes:			
Electric	$ 8,308	$ 4,303	$ 9,862
Natural gas distribution	2,240	(3,883)	1,823
Construction services	9,693	(3,345)	3,905
Pipeline and energy services	13,004	7,445	11,188
Natural gas and oil production	82,428	61,261	42,993
Construction materials and mining	29,244	26,674	28,168
Independent power production	483	1,249	257
Other	379	270	376
Total income taxes	$ 145,779	$ 93,974	$ 98,572
Cumulative effect of accounting change (Note 8):			
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Construction services	---	---	---
Pipeline and energy services	---	---	---
Natural gas and oil production	---	---	(7,740)
Construction materials and mining	---	---	151
Independent power production	---	---	---
Other	---	---	---
Total cumulative effect of accounting change	$ ---	$ ---	$ (7,589)
Earnings on common stock:			
Electric	$ 13,940	$ 12,790	$ 16,950
Natural gas distribution	3,515	2,182	3,869
Construction services	14,558	(5,650)	6,170
Pipeline and energy services	22,092	8,944	18,158
Natural gas and oil production	141,625	110,779	63,027
Construction materials and mining	55,040	50,707	54,412
Independent power production	22,921	26,309	11,415

Other	707	321	606
Total earnings on common stock	$ 274,398	$ 206,382	$ 174,607
Capital expenditures:			
Electric	$ 27,036	$ 18,767	$ 28,537
Natural gas distribution	17,224	17,384	15,672
Construction services	50,900	8,470	7,820
Pipeline and energy services	36,399	38,282	93,004
Natural gas and oil production	329,773	111,506	101,698
Construction materials and mining	161,977	133,080	128,487
Independent power production	135,778	76,246	110,963
Other	11,913	4,215	1,895
Net proceeds from sale or disposition of property	(40,554)	(20,518)	(14,439)
Total net capital expenditures	$ 730,446	$ 387,432	$ 473,637
Identifiable assets:			
Electric*	$ 330,327	$ 323,819	$ 327,899
Natural gas distribution*	271,653	252,582	234,948
Construction services	351,654	230,955	221,824
Pipeline and energy services	466,961	447,302	405,904
Natural gas and oil production	898,883	685,610	602,389
Construction materials and mining	1,498,338	1,345,547	1,248,607
Independent power production	483,900	349,752	241,918
Other**	121,846	97,954	97,103
Total identifiable assets	$ 4,423,562	$3,733,521	$3,380,592
Property, plant and equipment:			
Electric*	$670,771	$ 650,902	$ 639,893
Natural gas distribution*	277,288	264,496	252,591
Construction services	90,110	82,600	76,871
Pipeline and energy services	522,796	492,400	461,793
Natural gas and oil production	1,303,447	982,625	871,357
Construction materials and mining	1,310,426	1,190,468	1,080,399
Independent power production	391,611	250,602	184,127
Other	27,906	17,335	17,007
Less accumulated depreciation, depletion and amortization	1,544,462	1,358,723	1,187,105
Net property, plant and equipment	$3,049,893	$2,572,705	$2,396,933

* *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).*

Excluding the asset impairments at pipeline and energy services of $5.3 million (after tax) in 2004, earnings (loss) 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 mining, independent power production, and other are all from nonregulated operations. Capital expenditures for 2005, 2004 and 2003 include noncash transactions, including the issuance of the Company's equity securities in connection with acquisitions. The noncash transactions were $46.5 million, $33.1 million and $42.4 million in 2005, 2004 and 2003, respectively.

NOTE 14 - ACQUISITIONS

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

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

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

The above acquisitions were accounted for under the purchase method of accounting and, accordingly, the acquired assets and liabilities assumed have been preliminarily recorded at their respective fair values as of the date of acquisition. On certain of the above acquisitions made in 2005, final fair market values are pending the completion of the review of the relevant assets, liabilities and issues identified 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 15 - EMPLOYEE BENEFIT PLANS

The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. Effective January 1, 2006, the Company discontinued defined pension plan benefits to all nonunion and certain union employees hired after December 31, 2005. These employees that would have been eligible for defined pension plan benefits are eligible to receive additional defined contribution plan benefits. The Company uses a measurement date of December 31 for all of its pension and postretirement benefit plans. The Company recognized the effects of the 2003 Medicare Act during the second quarter of 2004. The net periodic benefit cost for 2004 reflects the effects of the 2003 Medicare Act. Changes in benefit obligation and plan assets for the years ended December 31 and amounts recognized in the Consolidated Balance Sheets at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$284,756	$261,335	$75,491	$88,381
Service cost	8,336	7,667	1,719	1,826
Interest cost	16,617	15,903	3,784	4,312
Plan participants' contributions	---	---	1,386	1,133
Amendments	451	---	743	(773)
Actuarial (gain) loss	7,046	12,240	(8,924)	(14,951)
Benefits paid	(13,813)	(12,389)	(4,388)	(4,437)
Benefit obligation at end of year	303,393	284,756	69,811	75,491

Change in plan assets:

Fair value of plan assets at beginning of year	239,522	223,043	50,978	47,234
Actual gain on plan assets	16,805	27,264	1,419	2,920
Employer contribution	2,814	1,604	3,053	4,127
Plan participants' contributions	---	---	1,386	1,134
Benefits paid	(13,813)	(12,389)	(4,388)	(4,437)
Fair value of plan assets at end of year	245,328	239,522	52,448	50,978
Funded status - under	(58,065)	(45,234)	(17,363)	(24,513)
Unrecognized actuarial (gain) loss	55,097	46,293	(7,621)	(1,832)
Unrecognized prior service cost	6,861	7,435	694	---
Unrecognized net transition obligation (asset)	(3)	(47)	14,878	16,999
Prepaid (accrued) benefit cost	$ 3,890	$8,447	$(9,412)	$(9,346)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Prepaid benefit cost	$ 18,690	$19,020	$ 787	$ 572
Accrued benefit liability	(14,800)	(10,573)	(10,199)	(9,918)
Additional minimum liability	(1,434)	---	---	---
Intangible asset	524	---	---	---
Accumulated other comprehensive income	910	---	---	---
Net amount recognized	$ 3,890	$8,447	$(9,412)	$(9,346)

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

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

The accumulated benefit obligation for the defined benefit pension plans reflected above was $244.3 million and $227.3 million at December 31, 2005 and 2004, 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, 2005 and 2004, were as follows:

	2005	2004
	(In thousands)	
Projected benefit obligation	$190,877	$174,983
Accumulated benefit obligation	$151,399	$136,012
Fair value of plan assets	$139,108	$132,280

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

	Pension Benefits			Other Postretirement Benefits		
Years ended December 31,	2005	2004	2003	2005	2004	2003
			(In thousands)			
Components of net periodic benefit cost:						
Service cost	$ 8,336	$ 7,667	$ 5,897	$ 1,719	$1,826	$1,857
Interest cost	16,617	15,903	15,211	3,784	4,312	5,281
Expected return on assets	(19,947)	(20,375)	(20,730)	(4,005)	(3,943)	(3,933)
Amortization of prior service cost	1,025	1,121	1,156	45	144	48
Recognized net actuarial (gain) loss	1,385	480	(417)	(549)	(233)	(255)
Amortization of net transition obligation (asset)	(45)	(250)	(950)	2,126	2,151	2,151
Net periodic benefit cost	7,371	4,546	167	3,120	4,257	5,149
Less amount capitalized	730	409	14	313	440	601
Net periodic benefit cost	$ 6,641	$4,137	$ 153	$ 2,807	$3,817	$4,548

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

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004
Discount rate	5.50%	5.75%	5.50%	5.75%
Rate of compensation increase	4.30%	4.70%	4.50%	4.50%

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

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004
Discount rate	5.75%	6.00%	5.75%	6.00%
Expected return on plan assets	8.50%	8.50%	7.50%	7.50%
Rate of compensation increase	4.70%	4.70%	4.50%	4.50%

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

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

	2005	2004
Health care trend rate assumed for next year	6.0%-9.5%	6.0%-9.5%
Health care cost trend rate - ultimate	5.0%-6.0%	5.0%-6.0%
Year in which ultimate trend rate achieved	1999-2014	1999-2013

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, 2005:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ (77)	$ (770)
Effect on postretirement benefit obligation	$441	$(7,499)

The Company's defined benefit pension plans' asset allocation at December 31, 2005 and 2004, and weighted average targeted asset allocations at December 31, 2005, were as follows:

	Percentage of Plan Assets		Weighted Average Targeted Asset Allocation Percentage
Asset Category	2005	2004	2005
Equity securities	74%	74%	70%
Fixed income securities	21	24	30*
Other	5	2	---
Total	100%	100%	100%

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

The Company's pension assets are managed by 10 outside investment managers. The Company's other postretirement assets are managed by one outside investment manager. The Company's investment policy with respect to pension and other postretirement assets is to make investments solely in the interest of the participants and beneficiaries of the plans and for the exclusive purpose of providing benefits accrued and defraying the reasonable expenses of administration. The Company strives to maintain investment diversification to assist in minimizing the risk of large losses. The Company's policy guidelines allow for investment of funds in cash equivalents, fixed income securities and equity securities. The guidelines prohibit investment in commodities and future contracts, equity private placement, employer securities, leveraged or derivative securities, options, direct real estate investments, precious metals, venture capital and limited partnerships. The guidelines also prohibit short selling and margin transactions. The Company's practice is to periodically review and rebalance asset categories based on its targeted asset allocation percentage policy.

The Company's other postretirement benefit plans' asset allocation at December 31, 2005 and 2004, and weighted average targeted asset allocation at December 31, 2005, were as follows:

Asset Category	Percentage of Plan Assets 2005	2004	Weighted Average Targeted Asset Allocation Percentage 2005
Equity securities	70%	70%	70%
Fixed income securities	28	28	30*
Other	2	2	---
Total	100%	100%	100%

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

The Company expects to contribute approximately $1.2 million to its defined benefit pension plans and approximately $3.3 million to its postretirement benefit plans in 2006.

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

Years	Pension Benefits	Other Postretirement Benefits
	(In thousands)	
2006	$ 13,118	$ 4,172
2007	13,554	4,344
2008	14,130	4,478
2009	14,915	4,675
2010	15,899	4,897
2011-2015	95,429	27,848

The following Medicare Part D subsidies are expected: $288,000 in 2006; $589,000 in 2007; $620,000 in 2008; $650,000 in 2009; $682,000 in 2010; and $4.0 million during the years 2011 through 2015.

In addition to company-sponsored plans, certain employees are covered under multi-employer defined benefit plans administered by a union. Amounts contributed to the multi-employer plans were $39.6 million, $28.2 million and $27.2 million in 2005, 2004 and 2003, respectively.

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this note, the Company also has an unfunded, nonqualified benefit plan for executive officers and certain key management employees that generally provides for defined benefit payments at age 65 following the employee's retirement or to their beneficiaries upon death for a 15-year period. Investments, at December 31, 2005, consisted of cash equivalents, fixed income securities, equity securities, and life insurance carried on plan participants, which is payable to the Company upon the employee's death. The Company's net periodic benefit cost for this plan was $7.4 million, $7.5 million and $5.3 million in 2005, 2004 and 2003, respectively. The total projected obligation for this plan was $64.9 million and $65.3 million at December 31, 2005 and 2004, respectively. The accumulated benefit obligation for this plan was $55.0 million and $52.3 million at December 31, 2005 and 2004, respectively. The additional minimum liability relating to this plan was $11.6 million and $14.3 million at December 31, 2005 and 2004, respectively. The Company had no related intangible asset as of December 31, 2005, and had a related intangible asset recognized as of December 31, 2004, of $851,000. A discount rate of 5.50 percent and 5.75 percent at December 31, 2005 and 2004, respectively, and a rate of compensation increase of 4.25 percent and 4.75 percent at December 31, 2005 and 2004, respectively, were used to determine benefit obligations.

A discount rate of 5.75 percent and 6.00 percent at December 31, 2005 and 2004, respectively, and a rate of compensation increase of 4.75 percent at both December 31, 2005 and 2004, were used to determine net periodic benefit cost. The decrease in minimum liability included in other comprehensive income was $1.1 million in 2005 and the increase in minimum liability in other comprehensive income was $3.8 million in 2004.

The amount of benefit payments for the unfunded, nonqualified benefit plan, as appropriate, are expected to aggregate $2.6 million in 2006; $2.9 million in 2007; $3.1 million in 2008; $3.3 million in 2009; $3.5 million in 2010; and $21.4 million for the years 2011 through 2015.

The Company sponsors various defined contribution pension plans for eligible employees. Costs incurred by the Company under these plans were $17.0 million in 2005, $13.8 million in 2004 and $9.8 million in 2003. The costs incurred in each year reflect additional participants as a result of business acquisitions.

NOTE 16 - JOINTLY OWNED FACILITIES

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

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

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

	2005	2004
	(In thousands)	
Big Stone Station:		
Utility plant in service	$ 56,305	$ 52,157
Less accumulated depreciation	38,011	36,488
	$ 18,294	$ 15,669
Coyote Station:		
Utility plant in service	$125,007	$124,388
Less accumulated depreciation	76,563	74,671
	$ 48,444	$ 49,717

NOTE 17 - REGULATORY MATTERS AND REVENUES SUBJECT TO REFUND

On September 30, 2005, Montana-Dakota filed an application with the MTPSC for a natural gas rate increase. Montana-Dakota requested a total increase of $1.1 million annually or 1.3 percent above current rates. On January 26, 2006, this application was withdrawn as a result of Montana-Dakota's implementation of cost-reduction measures.

In September 2004, Great Plains filed an application with the MPUC for a natural gas rate increase. Great Plains had requested a total increase of $1.4 million annually or approximately 4.0 percent above current rates. Great Plains also requested an interim increase of $1.4 million annually. In November 2004, the MPUC issued an Order authorizing an interim increase of $1.4 million annually effective with service rendered on or after January 10, 2005, subject to refund. A final order from the MPUC is expected in early 2006.

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

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) X An Original (2) _ A Resubmission	12/31/2005	2005/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

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. On April 19, 2005, the FERC issued its Order on Compliance Filing and Motion for Refunds. In this Order, the FERC approved Williston Basin's refund rates and established rates to be effective April 19, 2005. Williston Basin filed its compliance filing complying with the requirements of this Order regarding rates and issued refunds totaling approximately $18.5 million to its customers on May 19, 2005. As a result of the Order, Williston Basin recorded a $5.0 million (after tax) benefit from the resolution of the rate proceeding which included the reversal of a portion of the liability it had previously established for this regulatory proceeding. On June 16, 2005, Williston Basin appealed to the D.C. Appeals Court certain issues addressed by the FERC's Order on Initial Decision dated July 2003 and its Order on Rehearing dated May 2004 concerning determinations associated with cost of service and volumes used in allocating costs and designing rates. Those matters are pending resolution by the D.C. Appeals Court. A provision has been established for certain issues pending before the D.C. Appeals Court. The Company believes that the provision is adequate based on its assessment of the ultimate outcome of the proceeding.

In May 2004, the FERC remanded issues regarding certain service and annual demand quantity restrictions to an ALJ for resolution. Williston Basin participated in a hearing before the ALJ in early January 2005, regarding those service and annual demand quantity restrictions. On April 8, 2005, the ALJ issued an Initial Decision on the matters remanded by the FERC. In the Initial Decision, the ALJ decided that Williston Basin had not supported its position regarding the service and annual demand quantity restrictions. Williston Basin filed its Brief on Exceptions regarding these issues with the FERC on May 9, 2005, and its Brief Opposing Exceptions to issues raised by a certain party to the proceeding on May 31, 2005. On November 22, 2005, the FERC issued an Order on Initial Decision affirming the ALJ's Initial Decision regarding the service and annual demand quantity restrictions. On December 22, 2005, Williston Basin filed its Request for Rehearing of the FERC's Order on Initial Decision. This matter is awaiting resolution by the FERC.

NOTE 18 - COMMITMENTS AND CONTINGENCIES

Litigation

Royalties Case In June 1997, Grynberg filed suit under the Federal False Claims Act against Williston Basin and Montana-Dakota. Grynberg also filed more than 70 similar suits against natural gas transmission companies and producers, gatherers and processors of natural gas. Grynberg, acting on behalf of the United States under the Federal False Claims Act, alleged improper measurement of the heating content and volume of natural gas purchased by the defendants resulting in the underpayment of royalties to the United States. All cases were consolidated in the Wyoming Federal District Court.

In June 2004, following preliminary discovery, Williston Basin and Montana-Dakota joined with other defendants and filed a Motion to Dismiss on the ground that the information upon which Grynberg based his complaint was publicly disclosed prior to the filing of his complaint and further, that he is not the original source of such information. The Motion to Dismiss was heard on March 17 and 18, 2005, by the Special Master appointed by the Wyoming Federal District Court. The Special Master, in his Written Report dated May 13, 2005, recommended that the lawsuit be dismissed against certain defendants, including Williston Basin and Montana-Dakota. A hearing on the adoption of the Written Report was held on December 9, 2005, before the Wyoming Federal District Court.

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

Grynberg has not specified the amount he seeks to recover. Williston Basin and

Montana-Dakota are unable to estimate their potential exposure and will be unable to do so until discovery is completed.

Coalbed Natural Gas Operations Fidelity has been named as a defendant in, and/or certain of its operations are or have been the subject of, more than a dozen lawsuits filed in connection with its coalbed natural gas development in the Powder River Basin in Montana and Wyoming. These lawsuits were filed in federal and state courts in Montana between June 2000 and November 2004 by a number of environmental organizations, including the NPRC and the Montana Environmental Information Center, as well as the Tongue River Water Users' Association and the Northern Cheyenne Tribe. Portions of two of the lawsuits have been transferred to the Wyoming Federal District Court. The lawsuits involve allegations that Fidelity and/or various government agencies are in violation of state and/or federal law, including the Clean Water Act, the NEPA, the Federal Land Management Policy Act, the NHPA and the Montana Environmental Policy Act. The cases involving alleged violations of the Clean Water Act have been resolved without a finding that Fidelity is in violation of the Clean Water Act. There presently are no claims pending for penalties, fines or damages under the Clean Water Act. The suits that remain extant include a variety of claims that state and federal government agencies violated various environmental laws that impose procedural requirements and the lawsuits seek injunctive relief, invalidation of various permits and unspecified damages.

In suits filed in the Montana Federal District Court, the NPRC and the Northern Cheyenne Tribe asserted that further development by Fidelity and others of coalbed natural gas in Montana should be enjoined until the BLM completes a SEIS. The Montana Federal District Court, in February 2005, entered a ruling requiring the BLM to complete a SEIS. The Montana Federal District Court later entered an order that would have allowed limited coalbed natural gas development in the Powder River Basin in Montana pending the BLM's preparation of the SEIS. The plaintiffs appealed the decision to the Ninth Circuit. The Montana Federal District Court declined to enter an injunction requested by the NPRC and the Northern Cheyenne Tribe that would have enjoined development pending the appeal. In late May 2005, the Ninth Circuit granted the request of the NPRC and the Northern Cheyenne Tribe and, pending further order from the Ninth Circuit, enjoined the BLM from approving any new coalbed natural gas development projects in the Powder River Basin in Montana. That court also enjoined Fidelity from drilling any additional federally permitted wells in its Montana Coal Creek Project and from constructing infrastructure to produce and transport coalbed natural gas from the Coal Creek Project's existing federal wells. The matter has been fully briefed and argued before the Ninth Circuit and the parties are awaiting a decision of the court.

In related actions in the Montana Federal District Court, the NPRC and the Northern Cheyenne Tribe asserted, among other things, that the actions of the BLM in approving Fidelity's applications for permits and the plan of development for the Badger Hills Project in Montana did not comply with applicable Federal laws, including the NHPA and the NEPA. The NPRC also asserted that the Environmental Assessment that supported the BLM's prior approval of the Badger Hills Project was invalid. On June 6, 2005, the Montana Federal District Court issued orders in these cases enjoining operations on Fidelity's Badger Hills Project pending the BLM's consultation with the Northern Cheyenne Tribe as to satisfaction of the applicable requirements of NHPA and a further environmental analysis under NEPA. Fidelity has sought and obtained stays of the injunctive relief from the Montana Federal District Court and production from Fidelity's Badger Hills Project continues. On September 2, 2005, the Montana Federal District Court entered an Order based on a stipulation between the parties to the NPRC action that production from existing wells in Fidelity's Badger Hills Project may continue pending preparation of a revised environmental analysis. On November 1, 2005, the Montana Federal District Court entered an Order based on a stipulation between the parties to the Northern Cheyenne Tribe action that production from existing wells in Fidelity's Badger Hills Project may continue pending preparation of a revised environmental analysis. On December 16, 2005, Fidelity filed a Notice of Appeal to the Ninth Circuit.

The NPRC has filed a petition with the BER and the BER has initiated related rulemaking proceedings to create rules that would, if promulgated, require re-injection of water produced in connection with coalbed natural gas operations and treatment of such water in the event re-injection is not feasible and amend the nondegradation policy in connection with coalbed natural gas development. If the rules are adopted as proposed, it is possible that an adverse impact on Fidelity's operations could result. At this point, the Company cannot predict the outcome of the rulemaking process before the BER or its impact on the Company's operations.

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

Electric Operations Montana-Dakota has joined with two electric generators in appealing a finding by the ND Health Department in September 2003 that the ND Health Department may unilaterally revise operating permits previously issued to electric generating plants. Although it is doubtful that any revision of Montana-Dakota's operating permits by the ND Health Department would reduce the amount of electricity its plants could generate, the finding, if allowed to stand, could increase costs for sulfur dioxide removal and/or limit Montana-Dakota's ability to modify or expand operations at its North Dakota generation sites. Montana-Dakota and the other electric generators filed their appeal of the order in October 2003 in the Burleigh County District Court in Bismarck, North Dakota. Proceedings have been stayed pending discussions with the EPA, the ND Health Department and the other electric generators. The Company cannot predict the outcome of the ND Health Department matter or its ultimate impact on its operations.

Natural Gas Storage Williston Basin filed suit on January 27, 2006, seeking to recover unspecified damages from Anadarko and its wholly owned subsidiary, Howell, and to enjoin Anadarko's and Howell's present and future operations in and near Williston Basin's Elk Basin Storage Reservoir located in Wyoming and Montana. Based on relevant information, including reservoir and well pressure data, it appears that reservoir pressure has decreased and that quantities of gas may have been diverted by Anadarko's and Howell's drilling and production activities in areas within and near the boundaries of Williston Basin's Elk Basin Storage Reservoir. Williston Basin is seeking not only to recover damages for the gas that has been diverted, but to prevent further drainage of its storage reservoir. Williston Basin is also assessing further avenues for recovery through the regulatory process at the FERC. Because of the very preliminary stage of the legal proceedings, Williston Basin cannot estimate the size of any potential loss or recovery, or the likelihood of obtaining injunctive relief or recovery through the regulatory process.

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

Environmental matters

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

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

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

Operating leases
The Company leases certain equipment, facilities and land under operating lease agreements. The amounts of annual minimum lease payments due under these leases as of December 31, 2005, were $13.2 million in 2006, $8.6 million in 2007, $6.5 million in 2008, $4.2 million in 2009, $2.8 million in 2010 and $24.1 million thereafter. Rent expense was $34.0 million, $30.6 million and $27.2 million for the years ended December 31, 2005, 2004 and 2003, respectively.

Purchase commitments
The Company has entered into various commitments, largely natural gas and coal supply, purchased power, natural gas transportation, construction materials supply and electric generation construction contracts. These commitments range from one to 21 years. The commitments under these contracts as of December 31, 2005, were $303.6 million in 2006, $131.3 million in 2007, $79.5 million in 2008, $63.5 million in 2009, $62.7 million in 2010 and $294.4 million thereafter. Amounts purchased under various commitments for the years ended December 31, 2005, 2004 and 2003, were approximately $443.9 million, $318.3 million and $204.6 million, respectively. These commitments are not reflected in the Company's consolidated financial statements.

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

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 from approximately two 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.

In addition, WBI Holdings has guaranteed certain of Fidelity's natural gas and oil price swap and collar agreement obligations. Fidelity's obligations at December 31, 2005, were $16.3 million. There is no fixed maximum amount guaranteed in relation to the natural gas and oil price swap and collar agreements, as the amount of the obligation is dependent upon natural gas and oil commodity prices. The amount of hedging activity entered into by the subsidiary is limited by corporate policy. The guarantees of the natural gas and oil price swap and collar agreements at December 31, 2005, expire in 2006; however, Fidelity continues to enter into additional hedging activities and, as a result, WBI Holdings from time to time may issue additional guarantees on these hedging obligations. The amount outstanding by Fidelity was reflected on the Consolidated Balance Sheets at December 31, 2005. In the event Fidelity defaults under its obligations, WBI Holdings would be required to make payments under its guarantees.

Certain subsidiaries of the Company have outstanding guarantees to third parties that guarantee the performance of other subsidiaries of the Company. These guarantees are related to natural gas transportation and sales agreements, electric power supply agreements and certain other guarantees. At December 31, 2005, the fixed maximum amounts guaranteed under these agreements aggregated $73.6 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $8.5 million in 2006; $10.3 million in 2007; $400,000 in 2008; $900,000 in 2009; $30.0 million in 2010; $12.0 million in 2012; $2.0 million in 2028; $500,000, which is subject to expiration 30 days after the receipt of written notice; and $9.0 million, which has no scheduled maturity date. A guarantee for an unfixed amount estimated at $250,000 at December 31, 2005, has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above guarantees was $532,000 and was reflected on the Consolidated Balance Sheets at December 31, 2005. 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.

Centennial has outstanding letters of credit to third parties related to insurance policies and other agreements that guarantee the performance of other subsidiaries of the Company. At December 31, 2005, the fixed maximum amounts guaranteed under these letters of credit aggregated $32.3 million. The letters of credit are scheduled to expire in 2006. There were no amounts outstanding under the above letters of credit at December 31, 2005.

Fidelity and WBI Holdings have outstanding guarantees to Williston Basin. These guarantees are related to natural gas transportation and storage agreements that guarantee the performance of Prairielands. At December 31, 2005, the fixed maximum amounts guaranteed under these agreements aggregated $22.9 million. Scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $2.9 million in 2008 and $20.0 million in 2009. In the event of Prairielands' default in its payment obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee. The amount outstanding by Prairielands under the above guarantees was $1.7 million, which was not reflected on the Consolidated Balance Sheets at December 31, 2005, because these intercompany transactions are eliminated in consolidation.

In addition, Centennial has issued guarantees to third parties related to the Company's routine purchase of maintenance items and lease obligations for which no fixed maximum amounts have been specified. These guarantees have no scheduled maturity date. In the event a subsidiary of the Company defaults under its obligation in relation to the purchase of certain maintenance items or lease obligations, Centennial would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these maintenance items and lease obligations were reflected on the Consolidated Balance Sheets at December 31, 2005.

As of December 31, 2005, Centennial was contingently liable for the performance of certain of its subsidiaries under approximately $454 million of surety bonds. These bonds are principally for construction contracts and reclamation obligations of these subsidiaries entered into in the normal course of business. Centennial indemnifies the respective surety bond companies against any exposure under the bonds. The purpose of Centennial's indemnification is to allow the subsidiaries to obtain bonding at competitive rates. In the event a subsidiary of the Company does not fulfill its obligations in relation to its bonded contract or obligation, Centennial may be required to make payments under its indemnification. A large portion of these contingent commitments is expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) X An Original (2) _ A Resubmission	12/31/2005	2005/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

bonds for its subsidiaries in the future. The surety bonds were not reflected on the Consolidated Balance Sheets.

NOTE 19 - RELATED PARTY TRANSACTIONS
In 2004, Bitter Creek entered into two natural gas gathering agreements with Nance Petroleum. Robert L. Nance, an executive officer and shareholder of St. Mary, also is a member of the Board of Directors of the Company. The natural gas gathering agreements with Nance Petroleum were effective upon completion of certain high and low pressure gathering facilities, which occurred in mid-December 2004. Bitter Creek's capital expenditures related to the completion of the gathering lines and the expansion of its gathering facilities to accommodate the natural gas gathering agreements were $2.5 million and $7.6 million in 2005 and 2004, respectively, and are estimated for the next three years to be $2.2 million in 2006, $3.3 million in 2007 and $500,000 in 2008. The natural gas gathering agreements are each for a term of 15 years and month-to-month thereafter. Bitter Creek's revenues from these contracts were $1.2 million and $37,000 in 2005 and 2004, respectively, and estimated revenues from these contracts for the next three years are $2.8 million in 2006, $3.5 million in 2007 and $5.4 million in 2008. The amount due from Nance Petroleum at December 31, 2005, was $118,000.

In 2005, Montana-Dakota entered into agreements to purchase natural gas from Nance Petroleum through March 31, 2006. Montana-Dakota's expenses under these agreements were $4.2 million in 2005. Montana-Dakota estimates that it will purchase approximately $2.2 million of natural gas from Nance Petroleum in 2006. The amount due to Nance Petroleum at December 31, 2005, was $686,000.

In 2005, Fidelity entered into an agreement for the purchase of an ownership interest in a natural gas and oil property with a third party whereunder it became a party to a joint operating agreement in which St. Mary is the operator of the property. St. Mary receives an overhead fee as operator of this property. The Company recorded its proportionate share of capital costs allocable to its ownership interest in the related property, which were not material to Fidelity.

NOTE 20
Investment in Subsidiaries
The Respondent owns one wholly owned subsidiary, Centennial Energy Holdings, Inc.

The financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America. As required by the Federal Energy Regulatory Commission for Form 1 report purposes, MDU Resources Group, Inc. reports its subsidiary investment using the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiary, as required by generally accepted accounting principles. If generally accepted accounting principles were followed, utility plant, other property and investments would increase by $1,042,573,034; current and accrued assets would increase by $757,217,104; deferred debits would increase by $276,891,174; long-term debt would increase by $918,779,542; other noncurrent liabilities and current and accrued liabilities would increase by $473,258,965; deferred credits would increase by $684,642,805 as of December 31, 2005. Furthermore, operating revenues would increase by $2,889,976,026 and operating expenses, excluding income taxes, would increase by $2,478,392,222 for the twelve months ended December 31, 2005. In addition, net cash provided by operating activities would increase by $427,072,000; net cash used in investing activities would increase by $634,630,000; net cash used in financing activities would decrease by $208,828,000; and the net change in cash and cash equivalents would be an increase of $1,270,000 for the twelve months ended December 31, 2005. Reporting its subsidiary investment using the equity method rather than generally accepted accounting principles has no effect on net income or retained earnings.

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2005

	Account Number & Title		Last Year	This Year	% Change
1	**Intangible Plant**				
2					
3	301	Organization			
4	302	Franchises & Consents			
5	303	Miscellaneous Intangible Plant	$2,522,804	$2,610,507	3.48%
6					
7	**TOTAL Intangible Plant**		$2,522,804	$2,610,507	3.48%
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: 2005

	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: 2005

	Account Number & Title		Last Year	This Year	% Change
1					
2	**Distribution Plant**				
3					
4	374	Land & Land Rights	$36,193	$36,193	
5	375	Structures & Improvements	195,171	195,171	
6	376	Mains	22,845,547	23,438,845	2.60%
7	377	Compressor Station Equipment			
8	378	Meas. & Reg. Station Equipment-General	552,195	550,256	-0.35%
9	379	Meas. & Reg. Station Equipment-City Gate	128,221	128,221	
10	380	Services	12,957,239	13,896,561	7.25%
11	381	Meters	11,231,759	11,765,756	4.75%
12	382	Meter Installations			
13	383	House Regulators	1,512,831	1,577,859	4.30%
14	384	House Regulator Installations			
15	385	Industrial Meas. & Reg. Station Equipment	178,175	178,175	
16	386	Other Prop. on Customers' Premises 1/	161,799	161,799	
17	387	Other Equipment	948,076	970,931	2.41%
18					
19	**TOTAL Distribution Plant**		$50,747,206	$52,899,767	4.24%
20					
21	**General Plant**				
22					
23	389	Land & Land Rights	$26,745	$26,744	
24	390	Structures & Improvements	453,537	453,537	
25	391	Office Furniture & Equipment	403,189	415,589	3.08%
26	392	Transportation Equipment	2,399,189	2,291,170	-4.50%
27	393	Stores Equipment	43,786	43,786	
28	394	Tools, Shop & Garage Equipment	557,911	609,041	9.16%
29	395	Laboratory Equipment	19,727	19,696	-0.16%
30	396	Power Operated Equipment	1,572,543	1,502,175	-4.47%
31	397	Communication Equipment	292,484	292,484	
32	398	Miscellaneous Equipment	14,312	14,310	-0.01%
33	399	Other Tangible Property			
34					
35	**TOTAL General Plant**		$5,783,423	$5,668,532	-1.99%
36					
37	**Common Plant**				
38					
39	389	Land & Land Rights	$188,049	$200,799	6.78%
40	390	Structures & Improvements	2,197,417	2,377,161	8.18%
41	391	Office Furniture & Equipment	847,937	834,851	-1.54%
42	392	Transportation Equipment	1,148,676	1,133,785	-1.30%
43	393	Stores Equipment	9,614	9,551	-0.66%
44	394	Tools, Shop & Garage Equipment	158,855	155,985	-1.81%
45	396	Power Operated Equipment			
46	397	Communication Equipment	293,537	275,020	-6.31%
47	398	Miscellaneous Equipment	74,969	75,442	0.63%
48					
49	**TOTAL Common Plant**		$4,919,054	$5,062,594	2.92%
50					
51	**TOTAL Gas Plant in Service**		$63,972,487	$66,241,400	3.55%

1/ Includes gas plant leased to others.

MONTANA DEPRECIATION SUMMARY

Year: 2005

	Functional Plant Classification	Plant Cost	Accumulated Depreciation Last Year Bal.	Accumulated Depreciation This Year Bal.	Current Avg. Rate
1	Production & Gathering				
2	Products Extraction				
3	Underground Storage				
4	Other Storage				
5	Transmission				
6	Distribution	$52,899,767	$33,380,517	$34,426,838	3.19%
7	General	5,721,902	2,334,343	2,697,521	3.54%
8	Common	7,619,731	3,029,394	3,355,879	6.06%
9	**TOTAL**	$66,241,400	$38,744,254	$40,480,238	3.55%

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)	$402,977	$413,587	2.63%
11	Assigned to Other			
12	155 Merchandise			
13	156 Other Materials & Supplies			
14	163 Stores Expense Undistributed			
15				
16	**TOTAL Materials & Supplies**	$402,977	$413,587	2.63%

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS

SCHEDULE 22

	Commission Accepted - Most Recent		% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number	D95.7.90			
2	Order Number	5856b			
3					
4	Common Equity		44.810%	12.000%	5.377%
5	Preferred Stock		1.810%	4.653%	0.084%
6	Long Term Debt		53.390%	10.212%	5.452%
7	Other				
8	**TOTAL**				10.913%
9					
10	Actual at Year End				
11					
12	Common Equity		56.209%	12.000%	6.745%
13	Preferred Stock		4.560%	4.612%	0.210%
14	Long Term Debt		35.622%	8.794%	3.133%
15	Short Term Debt		3.609%	5.163%	0.186%
16	**TOTAL**		100.000%		10.274%

STATEMENT OF CASH FLOWS

Year: 2005

	Description	Last Year	This Year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2				
3	**Cash Flows from Operating Activities:**			
4	Net Income	$207,066,607	$275,082,651	32.85%
5	Depreciation	29,529,445	30,352,510	2.79%
6	Amortization	1,140,203	947,347	-16.91%
7	Deferred Income Taxes - Net	(2,008,646)	(12,462,831)	520.46%
8	Investment Tax Credit Adjustments - Net	(592,197)	(499,604)	-15.64%
9	Change in Operating Receivables - Net	3,643,265	(21,779,728)	-697.81%
10	Change in Materials, Supplies & Inventories - Net	(3,986,837)	20,226	100.51%
11	Change in Operating Payables & Accrued Liabilities - Net	17,758,725	16,677,311	-6.09%
12	Change in Other Regulatory Assets	1,410,889	535,884	-62.02%
13	Change in Other Regulatory Liabilities	(3,403,165)	935,646	127.49%
14	Allowance for Funds Used During Construction (AFUDC)	(264,953)	(223,020)	-15.83%
15	Change in Other Assets & Liabilities - Net	(4,483,170)	23,524,096	624.72%
16	Less Undistributed Earnings from Subsidiary Companies	(191,408,704)	(256,943,375)	34.24%
17	Other Operating Activities (explained on attached page)			
18	**Net Cash Provided by/(Used in) Operating Activities**	$54,401,462	$56,167,113	3.25%
19				
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment			
22	(net of AFUDC & Capital Lease Related Acquisitions)	($36,250,756)	($41,690,838)	15.01%
23	Acquisition of Other Noncurrent Assets	(11,126,644)	(1,872,165)	-83.17%
24	Proceeds from Disposal of Noncurrent Assets			
25	Investments In and Advances to Affiliates	(75,952,020)	(41,246,406)	-45.69%
26	Contributions and Advances from Affiliates	64,106,000	75,434,000	17.67%
27	Disposition of Investments in and Advances to Affiliates			
28	Other Investing Activities: Depreciation & RWIP on Nonutility Plant	144,461	95,894	-33.62%
29	**Net Cash Provided by/(Used in) Investing Activities**	($59,078,959)	($9,279,515)	-84.29%
30				
31	**Cash Flows from Financing Activities:**			
32	Proceeds from Issuance of:			
33	Long-Term Debt		$23,000,000	100.00%
34	Preferred Stock			
35	Common Stock	$106,904,941	47,233,779	-55.82%
36	Other:			
37	Net Increase in Short-Term Debt			
38	Other: Commercial Paper			
39	Payment for Retirement of:			
40	Long-Term Debt	(19,600,000)	(20,950,000)	6.89%
41	Preferred Stock			0.00%
42	Common Stock			
43	Other: Adjustment to Retained Earnings	(231,602)	(330,879)	-42.87%
44	Net Decrease in Short-Term Debt			
45	Dividends on Preferred Stock	(685,004)	(685,004)	0.00%
46	Dividends on Common Stock	(82,340,948)	(88,366,793)	7.32%
47	Other Financing Activities (explained on attached page)			
48	**Net Cash Provided by (Used in) Financing Activities**	$4,047,387	($40,098,897)	-1090.74%
49				
50	**Net Increase/(Decrease) in Cash and Cash Equivalents**	($630,110)	$6,788,701	-1177.38%
51	**Cash and Cash Equivalents at Beginning of Year**	$9,406,755	$8,776,645	-6.70%
52	**Cash and Cash Equivalents at End of Year**	$8,776,645	$15,565,346	77.35%

LONG TERM DEBT

Year: 2005

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost % 1/
1	8.25 % Secured MTN, Series A	04/92	04/07	$30,000,000	$26,111,796	$30,000,000	8.25%	$3,053,100	10.18%
2	8.60 % Secured MTN, Series A	04/92	04/12	35,000,000	28,906,532	35,000,000	8.60%	3,857,000	11.02%
3	6.71 % Secured MTN, Series A	09/97	10/09	15,000,000	13,488,404	15,000,000	6.71%	1,229,250	8.20%
4	5.83 % Secured MTN, Series A	09/98	10/08	15,000,000	14,813,914	15,000,000	5.83%	912,900	6.09%
5	5.98 % Senior Notes	12/03	12/33	30,000,000	29,456,832	30,000,000	5.98%	1,861,500	6.21%
6									
7									
8									
9									
10									
11									
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16									
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18									
19									
20									
21									
22									
23									
24									
25									
26	**TOTAL**			$125,000,000	$112,777,478	$125,000,000		$10,913,750	8.73%

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

PREFERRED STOCK

Year: 2005

	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 % Cummulative 2/	05/61	50,000	100	102	4,947,548	5.29%	1,000,000	52,850	5.29%
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32	**TOTAL**					$19,947,548		$16,000,000	$737,850	4.61%

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

COMMON STOCK

Year: 2005

		Avg. Number of Shares Outstanding 1/	Book Value Per Share	Earnings Per Share 2/	Dividends Per Share	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio 3/
1									
2									
3									
4	January								
5									
6	February								
7									
8	March	117,826,756	$14.02	$0.29	$0.18	37.93%	$28.50	$25.48	15.0 X
9									
10	April								
11									
12	May								
13									
14	June	118,348,198	14.70	0.68	0.18	73.53%	29.34	26.35	13.9 X
15									
16	July								
17									
18	August								
19									
20	September	119,619,007	14.78	0.73	0.19	73.97%	36.07	28.08	16.7 X
21									
22	October								
23									
24	November								
25									
26	December	119,815,287	15.65	0.61	0.19	68.85%	37.13	30.85	14.3 X
27									
28									
29									
30	TOTAL Year End	118,909,724	$15.65	$2.31	$0.74	67.97%			14.3 X

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

MONTANA EARNED RATE OF RETURN

Year: 2005

		Description	Last Year	This Year	% Change
		Rate Base			
1					
2	101	Plant in Service	$63,972,487	$66,241,400	3.55%
3	108	(Less) Accumulated Depreciation	38,744,254	40,480,238	4.48%
4					
5		**NET Plant in Service**	$25,228,233	$25,761,162	2.11%
6					
7		CWIP in Service Pending Reclassification	$548,987	$711,152	29.54%
8					
9		Additions			
10	154, 156	Materials & Supplies	$402,977	$413,587	2.63%
11	165	Prepayments	44,033	26,073	-40.79%
12		Prepaid Demand/Commodity Charges	1,359,433	1,131,518	-16.77%
13		Gas in Underground Storage	7,259,116	7,043,943	-2.96%
14		Unamoritzed Gas IRP	18,291		-100.00%
15					
16		**TOTAL Additions**	$9,083,850	$8,615,121	-5.16%
17					
18		Deductions			
19	190	Accumulated Deferred Income Taxes	$3,705,125	$3,425,445	-7.55%
20	252	Customer Advances for Construction	349,329	405,582	16.10%
21	255	Accumulated Def. Investment Tax Credits	177,056	144,798	-18.22%
22		Other Deductions			
23					
24		**TOTAL Deductions**	$4,231,510	$3,975,825	-6.04%
25		**TOTAL Rate Base**	$30,629,560	$31,111,610	1.57%
26					
27		**Net Earnings**	$1,556,476	$1,924,247	23.63%
28					
29		**Rate of Return on Average Rate Base**	5.28%	6.23%	17.99%
30					
31		**Rate of Return on Average Equity**	2.76%	4.81%	74.28%
32					
33	Major Normalizing Adjustments & Commission				
34	Ratemaking adjustments to Utility Operations 1/				
35					
36	Adjustment to Operating Revenues				
38	Weather Normalization		544,074	271,476	-50.10%
39	Late Payment Revenue		31,373	57,841	84.37%
40					
41	Adjustment to Operating Expenses				
42	Elimination of Promotional & Institutional Advertising		(41,621)	(33,991)	-18.33%
43	Elimination of Supplemental Insurance			(138,869)	100.00%
44					
45	Total Adjustments to Operating Income		$617,068	$502,177	-18.62%
46					
47		**Adjusted Rate of Return on Average Rate Base**	7.37%	7.86%	6.65%
48					
49		**Adjusted Rate of Return on Average Equity**	6.80%	7.71%	13.38%

1/ Updated amounts, net of taxes.

MONTANA COMPOSITE STATISTICS

Year: 2005

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	$60,960
5	107	Construction Work in Progress	1,026
6	114	Plant Acquisition Adjustments	
7	104	Plant Leased to Others	13
8	105	Plant Held for Future Use	
9	154, 156	Materials & Supplies	414
10		(Less):	
11	108, 111	Depreciation & Amortization Reserves	40,480
12	252	Contributions in Aid of Construction	406
13			
14		**NET BOOK COSTS**	$21,527
15			
16		Revenues & Expenses (000 Omitted)	
17			
18	400	Operating Revenues	$97,138
19			
20	403 - 407	Depreciation & Amortization Expenses	$2,352
21		Federal & State Income Taxes	673
22		Other Taxes	2,449
23		Other Operating Expenses	89,739
24		TOTAL Operating Expenses	$95,213
25			
26		Net Operating Income	$1,925
27			
28		Other Income	87
29		Other Deductions	1,040
30			
31		**NET INCOME**	$972
32			
33		Customers (Intrastate Only)	
34			
35		Year End Average:	
36		Residential	65,393
37		Firm General	7,927
38		Small Interruptible	41
39		Large Interruptible	5
40			
41		**TOTAL NUMBER OF CUSTOMERS**	73,366
42			
43		Other Statistics (Intrastate Only)	
44			
45		Average Annual Residential Use (Dkt))	86
46		Average Annual Residential Cost per (Dkt) ($) * 1/	$13.53
		* Avg annual cost = [(cost per Dkt x annual use) +	
47		(monthly service charge x 12)]/annual use	
48		Average Residential Monthly Bill	$76.77
49		Gross Plant per Customer	$831

1/ Reflects cost per dk effective December 1, 2005.

MONTANA CUSTOMER INFORMATION

Year: 2005

	City/Town	Population (Includes Rural) 1/	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Belfry	219	135	19		154
2	Billings	89,847	42,095	4,033		46,128
3	Bridger	745	401	65		466
4	Crow Agency	1,552	310	67		377
5	Edgar	Not Available	104	8		112
6	Fromberg	486	282	20		302
7	Hardin	3,384	1,264	204		1,468
8	Joliet	575	350	43		393
9	Laurel	6,255	3,532	266		3,798
10	Park City	870	502	23		525
11	Pryor	628	89	13		102
12	Rockvale	Not Available	62	4		66
13	Silesia	Not Available	33	2		35
14	Warren	Not Available		2		2
15	Alzada	Not Available	9	7		16
16	Baker	1,695	801	170		971
17	Carlyle	Not Available	8	1		9
18	Fort Peck	240	126	11		137
19	Fairview	709	350	52		402
20	Forsyth	1,944	867	147		1,014
21	Frazer	452	97	13		110
22	Glasgow	3,253	1,631	299		1,930
23	Glendive	4,729	2,956	403		3,359
24	Hinsdale	Not Available	113	19		132
25	Ismay	26	8	4		12
26	Malta	2,120	986	200		1,186
27	Miles City	8,487	3,877	529		4,406
28	Nashua	325	179	19		198
29	Poplar	911	847	134		981
30	Richey	189	126	25		151
31	Rosebud	Not Available	43	6		49
32	Saco	224	41	8		49
33	Savage	Not Available	148	18		166
34	Sidney	4,774	2,269	398		2,667
35	Terry	611	310	60		370
36	St. Marie	183	146	12		158
37	Wibaux	567	211	50		261
38	Whitewater	Not Available	33	10		43
39	Wolf Point	2,663	1,379	201		1,580
40	MT Oil Fields	Not Available	2	3		5
41	**TOTAL Montana Customers**	138,663	66,722	7,568		74,290

1/ 2000 Census.

MONTANA EMPLOYEE COUNTS 1/

Year: 2005

	Department	Year Beginning	Year End	Average
1	Electric	21	20	20.5
2	Gas	45(1)	44	44.5(.5)
3	Accounting	19	20	19.5
5	Management	8	7	7.5
7	Service 2/	55(3)	53(2)	54(2.5)
4	Marketing/Communications	7	6	6.5
6	Power	26	26	26.0
10				
11				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	**TOTAL Montana Employees**	181(4)	176(2)	178.5(3)

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

Company Name: Montana-Dakota Utilities Co. SCHEDULE 31

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) Year: 2005

	Project Description	Total Company	Total Montana	
1	Projects>$1,000,000			
2				
3	Electric-Steam Production			
4	Replace Unit #2 Turbine Components at Heskett Station	1,744,259	451,887	1/
5	Extend Rail Car Unloading System at Heskett Station	1,282,450	332,246	1/
6	Install Coal Reclaim System at Heskett Station	1,131,831	293,225	1/
7	Reinsulate and Relag Unit #2 Boiler at Heskett Station	1,059,791	274,561	1/
8				
9	Electric-Distribution			
10	Add Second Transformer at SE Bismarck, ND Substation	1,544,310	0	
11				
12	Gas-Distribution			
13	Install Automated Meter Reading System	3,904,035	0	
14				
15	Other Projects<$1,000,000			
16				
17	Electric			
18	Production	29,670,096	2,259,348	1/
19	Transmission:			
20	Integrated	3,764,731	995,544	1/
21	Direct	2,332,395	827,701	2/
22	Distribution	8,713,514	1,578,575	2/
23	General	2,192,459	602,407	2/
24	Common:			
25	General Office	1,207,577	285,664	1/
26	Other Direct	1,287,439	172,307	2/
27	Total Electric	49,168,211	6,721,546	
28				
29	Gas			
30	Distribution	11,086,507	4,301,920	2/
31	General	2,707,438	920,894	2/
32	Common:			
33	General Office	972,166	254,535	1/
34	Other Direct	1,065,295	627,034	2/
35	Total Gas	15,831,406	6,104,383	
36				
37				
38				
39				
40				
41	TOTAL	$75,666,293	$14,177,848	

1/ Allocated to Montana.

2/ Directly assigned to Montana.

TRANSMISSION SYSTEM - TOTAL COMPANY & MONTANA

Year: 2005

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

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

DISTRIBUTION SYSTEM - TOTAL COMPANY & MONTANA

Year: 2005

	Total Company			
		Peak Day of Month	Peak Day Volumes Dkt	Total Monthly Volumes Dkt
1	January	13	317,408	7,449,802
2	February	7	252,073	5,118,466
3	March	14	201,589	4,775,741
4	April	27	147,381	3,012,079
5	May	1	144,923	2,410,145
6	June	1	69,289	1,648,675
7	July	25	57,206	1,502,490
8	August	9	63,550	1,637,863
9	September	28	73,208	1,697,575
10	October	5	158,072	3,484,701
11	November	30	235,824	4,733,526
12	December	6	288,605	6,572,732
13	**TOTAL**			44,043,795

	Montana			
		Peak Day of Month	Peak Day Volumes Dkt	Total Monthly Volumes Dkt
14	January	14	106,113	2,320,114
15	February	7	76,650	1,532,258
16	March	23	65,364	1,506,581
17	April	19	45,253	1,011,963
18	May	11	50,723	752,605
19	June	9	26,789	610,329
20	July	25	24,250	564,774
21	August	10	31,222	672,377
22	September	24	32,454	675,073
23	October	5	59,571	1,364,150
24	November	30	80,697	1,541,176
25	December	7	91,455	2,128,906
26	**TOTAL**			14,680,306

STORAGE SYSTEM - TOTAL COMPANY & MONTANA

		Total Company						
		Peak Day of Month		Peak Day Volumes (Dkt)		Total Monthly Volumes (Dkt)		
		Injection	Withdrawal	Injection	Withdrawal	Injection	Withdrawal	Losses
1	January	24	13	1,602	184,828	6,798	3,396,609	
2	February	8	7	1,751	129,513	9,132	1,729,573	
3	March	28	24	19,338	70,993	58,401	1,078,833	
4	April	17	30	49,867	33,896	655,213	186,866	
5	May	20	1	56,197	35,678	1,096,597	117,007	
6	June	18	9	65,915	282	1,612,345	621	
7	July	1	21	63,297	436	1,768,215	1,395	
8	August	16	21	72,730	432	1,958,063	2,286	
9	September	4	28	68,127	286	1,713,409	891	
10	October	1	5	55,604	30,745	529,023	149,427	
11	November	11	30	37,805	93,753	202,094	712,188	
12	December	25	6	4,529	151,943	21,081	2,429,073	
13	**TOTAL**					9,630,371	9,804,769	

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

SOURCES OF GAS SUPPLY

Year: 2005

	Name of Supplier 1/	Last Year Volumes Dkt	This Year Volumes Dkt	Last Year Avg. Commodity Cost	This Year Avg. Commodity Cost
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29	1/ Supplier information is proprietary and confidential.				
30					
31					
32					
33	**Total Gas Supply Volumes**	34,234,195	32,653,681	$5.196	$7.006

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2005

	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	$13,305	$0	100.00%	N/A	N/A	N/A
3	(As Detailed on Schedule 36B)						
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32	**TOTAL**	$13,305	$0	100.00%	N/A	N/A	N/A

MONTANA CONSUMPTION AND REVENUES

Year: 2005

	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	$60,243,176	$46,458,146	5,635,528	5,249,842	65,393	64,390
2	Firm General	34,499,786	25,788,978	3,308,993	3,013,007	7,927	7,828
3	Small Interruptible	228,089	657,161	24,649	84,128	3	4
4	Large Interruptible	15,754	28,507	1,810	4,647		
5							
6							
7							
8							
9							
10							
11	TOTAL	$94,986,805	$72,932,792	8,970,980	8,351,624	73,323	72,222
12							
13							
14		Operating Revenues		BCF Transported		Avg. No. of Customers	
15							
16							
17	Transportation of Gas	Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
18							
19	Small Interruptible	$754,424	$725,181	0.9	0.9	38	37
20	Large Interruptible	914,287	582,924	4.9	4.2	5	5
21							
22							
23							
24	TOTAL	$1,668,711	$1,308,105	5.8	5.1	43	42

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

NATURAL GAS UNIVERSAL SYSTEM BENEFITS PROGRAMS

Year: 2005

	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	$283,095	$0	$283,095		
24						
25						
26						
27						
28						
29	Other					
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42	Total	$283,095	$0	$283,095		2005
43	Number of customers that received low income rate discounts			(Average)	2,734	
44	Average monthly bill discount amount ($/mo)				$8.63	
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	

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS Year: 2005

	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	Conservation Starter Kits	$12,230	$0	$12,230		
3						
4	Furnace Incentive	450	0	450	26.7	
5						
6	Thermostat Incentive	160	0	160	29.6	
7						
8	Water Heater Incentive	30	0	30	0.7	
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	Open House	$435	$0	$435		
39						
40						
41						
42						
43						
44						
45						
46						
47	Total	$13,305	$0	$13,305	57.0	2005