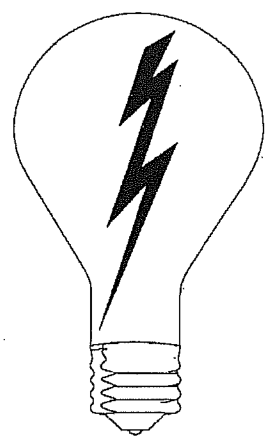
YEAR ENDING 2011

ANNUAL REPORT
OF

MONTANA-DAKOTA UTILITIES CO.

ELECTRIC UTILITY



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

REVISED - 2005

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

IDENTIFICATION

Year: 2011

1.	Legal Name of Respondent:	MDU Resources Group, Inc.
2.	Name Under Which Respondent Does Business:	Montana-Dakota Utilities Co.
3.	Date Utility Service First Offered in Montana	1920
4.	Address to send Correspondence Concerning Report:	Montana-Dakota Utilities Co. 400 North Fourth Street Bismarck, ND 58501
5.	Person Responsible for This Report:	Rita A. Mulkern
5a.	Telephone Number:	(701) 222-7854

Control Over Respondent

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

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

   1b. Means by which control was held:

   1c. Percent Ownership:

SCHEDULE 2

Board of Directors [1/]

Line No.	Name of Director and Address (City, State) (a)	Remuneration (b)
1	Terry D. Hildestad, Bismarck, ND	-
2	Doran N. Schwartz, Bismarck, ND	-
3	Paul K. Sandness, Bismarck, ND	-
4	David L. Goodin, Bismarck, ND	-
5		-
6		-
7		
8	1/ Montana-Dakota Utilities Co. is a division of MDU Resources Group, Inc.,	
9	and has no Board of Directors. The affairs of the Company are managed by	
10	a Managing Committee, the members of which are provided herein rather	
11	than the directors of MDU Resources Group, Inc.	
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Officers

Year: 2011

Line No.	Title of Officer (a)	Department Supervised (b)	Name (c)
1	President & Chief	Executive	David L. Goodin
2	Executive Officer		
3			
4	Executive Vice President	Marketing, Gas Supply	Dennis L. Haider
5		and Business Development	
6			
7	Executive Vice President	Combined Utiility Operations Support	Mike J. Gardner
8			
9	Vice President	Electric Supply	Andrea L. Stomberg
10			
11	Vice President	Operations	Jay W. Skabo
12			
13	Vice President	Regulatory Affairs and Chief	Garret Senger
14		Accounting Officer	
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CORPORATE STRUCTURE

Year: 2011

Line	Subsidiary/Company Name	Line of Business	Earnings (000's)	Percent of Total
1	Montana-Dakota Utilities Co./	Electric and Natural Gas	$67,656	31.86%
2	Great Plains Natural Gas Co.	Distribution		
3	(Divisions of MDU Resources			
4	Group, Inc.) Cascade			
5	Natural Gas Corp. and			
6	Intermountain Gas Company			
8	WBI Holdings, Inc.	Pipeline and Energy Services and	103,364	48.68%
9		Natural Gas and Oil Production		
11	Knife River Corporation	Construction Materials and	26,430	12.45%
12		Mining		
14	MDU Construction Services	Construction Services	21,627	10.18%
15	Group, Inc.			
17	Centennial Energy Resources LLC/	Other	(6,736)	-3.17%
18	Centennial Holdings Capital LLC			
50	**TOTAL**		$212,341	100.00%

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

CORPORATE ALLOCATIONS - ELECTRIC

Year: 2011

Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
Audit Costs	Administrative & General	Various Corporate Overhead Allocation Factors	$3,311	1.89%	$171,783
Advertising	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	7,293	1.94%	368,601
Air Service	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	1,206	1.45%	82,079
Automobile	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	519	2.06%	24,624
Bank Services	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	6,735	1.89%	349,404
Computer Rental	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	102	1.89%	5,294
Consultant Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	10,942	1.82%	589,324
Contract Services	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	28,868	1.59%	1,785,664
Corporate Aircraft	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	2,140	1.94%	108,427
Directors Expenses	Administrative & General	Corporate Overhead Allocation Factor Based on a Combination of Net Plant Investment and Number of Employees	37,028	1.89%	1,920,885
Employee Benefits	Administrative & General	Corporate Overhead Allocation Factor Based on Number of Employees	3,279	1.91%	168,511

CORPORATE ALLOCATIONS - ELECTRIC

Year: 2011

Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
Employee Meetings	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	2,541	1.89%	131,797
Employee Reimbursable Expenses	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	2,705	1.65%	161,198
Legal Retainers & Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	20,916	1.89%	1,085,067
Meal Allowance	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	46	1.91%	2,368
Meals & Entertainment	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	1,993	1.75%	111,588
Moving Expense	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	95	1.90%	4,905
Industry Dues & Licenses	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	2,810	1.87%	147,087
Office Expenses	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	1,730	2.17%	77,812
Prepaid Insurance	Administrative & General	Various Corporate Overhead Allocation Factors and Allocation Factors Based on Actual Experience	20,709	1.70%	1,199,750
Permits and Filing Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	747	2.45%	29,764
Postage	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	383	1.88%	20,013

Company Name: Montana-Dakota Utilities Co.

CORPORATE ALLOCATIONS - ELECTRIC

Year: 2011

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Payroll	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	411,680	2.07%	19,493,870
4	Rental	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	80	2.13%	3,670
7	Reference Materials	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	3,596	1.95%	180,771
10	Reimbursements	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	(1,009)	1654.10%	948
13	Supplemental Insurance	Administrative & General	Various Corporate Overhead Allocation Factors	54,367	1.91%	2,798,978
15	Seminars & Meeting Registrations	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	1,632	1.92%	83,511
18	Software Maintenance	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	10,865	1.90%	559,589
21	Telephone & Cell Phones	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	3,367	1.40%	237,909
24	Training Material	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	1,138	2.17%	51,218
32	**TOTAL**			$641,814	1.97%	$31,956,409

Company Name: Montana-Dakota Utilities Co. SCHEDULE 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - ELECTRIC

Year: 2011

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		$10,670		$1,672
3		Office Expenses		3,471		729
4		Travel		286		
5						
6		Capital	Actual Costs Incurred			
7		Contract Services		13,030		3,085
8		Materials		29,697		
9						
10		Other Transactions/Reimbursements	Actual Costs Incurred			
11		Balance Sheet Acct		335,556		
12		Non Utility		8,031		
13		MDU Resources Cost Centers		856		
14						
15		Total Knife River Corporation Operating Revenues for the Year 2011			$1,510,010,000	
16		Excludes Intersegment Eliminations				
17						
18						
19						
20						
21						
22	**TOTAL**	**Grand Total Affiliate Transactions**		$401,597	0.0266%	$5,486

Company Name: Montana-Dakota Utilities Co. SCHEDULE 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - ELECTRIC

Year: 2011

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.**	Expense	Actual Costs Incurred			
2		Contract Services		$7,789		$2,192
3		Legal		12,000		12,000
4		Fuel		34,114		9,838
5						
6		Capital	Actual Costs Incurred			
7		Contract Services		535		129
8		Material		3,017		646
9						
10		Other Transactions/Reimbursements	Actual Costs Incurred			
11		Auto Clearing		14,731		
12		Balance sheet accounts		1,028,252		
13		Non Utility		11,014		
14		MDU Resources Cost Centers		12,474		
15						
16						
17						
18		Total WBI Holdings, Inc. Operating Revenues for the Year 2011			$731,929,000	
19		Excludes Intersegment Eliminations				
20						
21						
22	**TOTAL**	**Grand Total Affiliate Transactions**		$1,123,926	0.1536%	$24,805

Company Name: Montana-Dakota Utilities Co. SCHEDULE 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - ELECTRIC

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**MDU CONSTRUCTION**	Expense	Actual Costs Incurred			
2	**SERVICES GROUP, INC**	Miscellaneous Employee Benefits		$265		
3		Materials		13,777		
4						
5		Capital	Actual Costs Incurred			
6		Contract Services		605,542		
7		Materials		815		$348
8						
9		Other Transactions/Reimbursements	Actual Costs Incurred			
10		MDU Resources Cost Centers		11,601		
11		Non Utility		1,980		
12		Auto Clearing		88		
13						
14		Total MDU Construction Services Group, Inc Operating Revenues for the Year 2011			$854,389,000	
15		Excludes Intersegment Eliminations				
16						
17						
18						
19						
20						
21						
22	**TOTAL**	**Grand Total Affiliate Transactions**		$634,068	0.0742%	$348

Company Name: Montana-Dakota Utilities Co. SCHEDULE 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - ELECTRIC

Year: 2011

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 HOLDINGS**	Expense	* Various Corporate Overhead			
2	**CAPITAL, LLC**	Contract Services	Allocation Factors and/or	$116,885		$24,561
3		Corporate Aircraft	Actual Costs Incurred	34,043		8,242
4		Office Expense		234,522		49,280
5		Rent		152,024		31,945
6		Other		5		
7						
8		Capital	Actual Costs Incurred			
9		Corporate Aircraft		739		158
10		Materials		5,769		1,234
11		Other		2,943		84
12						
13		Other Transactions/Reimbursements	Actual Costs Incurred			
14		MDU Resources Cost Centers		348,255		
15		Balance Sheet Accounts		2,100,090		
16		Clearing Accounts		515,238		
17		Non Utility		3,179		
18						
19		Total Centennial Holdings Capital, LLC Operating Revenues for the Year 2011			$11,446,000	
20		Grand Total Affiliate Transactions				
21						
22	**TOTAL**	**Grand Total Affiliate Transactions**		$3,513,692	30.6980%	$115,504

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

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - ELECTRIC

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**MDU ENERGY CAPITAL**	Expense	Actual Costs Incurred			
2		Contract Services		$36,435		$7,474
3		Cost of Service		12,852		2,701
4		Materials		3,463		728
5		Office Expenses		28,947		5,586
6		Other		261		11
7						
8						
9						
10		Capital	Actual Costs Incurred			
11		Contract Services		25,966		5,290
12		Materials		24,419		5,299
13		Other		452		94
14						
15						
16		Other Transactions/Reimbursements	Actual Costs Incurred			
17		MDU Resources Cost Centers		2,529		
18		Auto Clearing		3,248		
19		Customer Advance		8,300		
20		Subsidiary Receivables		1,897		
21		Miscellaneous		1,160		
22		Non Utility		49,416		
23						
24						
25		Total MDU Energy Capital Operating Revenues for the Year 2011			$614,601,000	
26		Grand Total Affiliate Transactions				
27						
28	**TOTAL**	**Grand Total Affiliate Transactions**		$199,345	0.0324%	$27,183

Company Name: Montana-Dakota Utilities Co. SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	**KNIFE RIVER**	MDU RESOURCES GROUP, INC.				
2	**CORPORATION**	Corporate Overhead	* Various Corporate Overhead Allocation			
3		Audit Costs	Factors, Time Studies and/or Actual	$44,907		
4		Advertising	Costs Incurred	98,387		
5		Air Service		25,601		
6		Automobile		5,049		
7		Bank Services		91,555		
8		Corporate Aircraft		29,113		
9		Consultant Fees		153,734		
10		Contract Services		893,038		
11		Computer Rental		1,395		
12		Directors Expenses		503,601		
13		Employee Benefits		43,758		
14		Employee Meeting		35,099		
15		Employee Reimbursable Expense		49,429		
16		Express Mail		3		
17		Insurance		303,887		
18		Legal Retainers & Fees		285,037		
19		Moving Allowance		1,310		
20		Meal Allowance		620		
21		Cash Donations		19,242		
22		Meals & Entertainment		29,833		
23		Industry Dues & Licenses		39,030		
24		Office Expenses		26,346		
25		Supplemental Insurance		723,477		
26		Permits & Filing Fees		7,565		
27		Postage		5,196		
28		Payroll		5,337,349		
29		Reimbursements		13,760		
30		Reference Materials		46,856		
31		Rental		524		
32		Seminars & Meeting Registrations		22,603		
33		Software Maintenance		207,342		
34		Telephone/Cell Expenses		113,555		
35		Training		16,250		
36		**Total MDU Resources Group, Inc.**		$9,174,451	0.6289%	

Company Name: Montana-Dakota Utilities Co. SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	**KNIFE RIVER**	MONTANA-DAKOTA UTILITIES CO.				
2	**CORPORATION**	Office Services	* General Office Complex and Office			
3		Office Expenses	Supplies Cost of Service Allocation	$4		
4			Factors			
5						
6		Other Direct Charges	Actual Costs Incurred			
7		Vehicle Maintenance		4,314		
8		Communications		20,393		
9		Employee Discounts		40,446		
10		Dues, Permits, and Filing Fees		355		
11		Electric Consumption		57,782		
12		Gas Consumption		51,213		$28,200
13		Bank Fees		28,589		
14		Computer/Software Support		1,365,606		
15		Office Expense		2,219		
16		Cost of Service		334,608		79,753
17		Audit Costs		688,312		
18		Auto		8,435		
19		Travel		35,278		
20		Employee Benefits		(5,372)		
21		Contract Services		62,360		
22						
23		**Total Montana-Dakota Utilities Co.**		$2,694,542	0.1847%	$107,953
24						
25		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual Costs Incurred			
26		Federal & State Tax Liability Payments		$22,645,083		
27		Miscellaneous Reimbursements		(216,273)		
28						
29		**Total Other Transactions/Reimbursements**		$22,428,810	1.5374%	
30						
31		**Grand Total Affiliate Transactions**		$34,297,803	2.3509%	$107,953
32						
33		**Total Knife River Corporation Operating Expenses for 2011-Excludes Intersegment Eliminations**			$1,458,918,000	
34						

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

KNIFE RIVER CORPORATION

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

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	**WBI HOLDINGS, INC.**	MDU RESOURCES GROUP, INC.				
2		Corporate Overhead	* Various Corporate Overhead			
3		Audit Costs	Allocation Factors, Time	$59,099		
4		Advertising	Studies and/or Actual Costs	131,894		
5		Air Service	Incurred	23,905		
6		Automobile		11,187		
7		Bank Services		119,991		
8		Corporate Aircraft		36,567		
9		Consultant Fees		201,340		
10		Contract Services		374,599		
11		Computer Rental		1,810		
12		Directors Expenses		659,398		
13		Employee Benefits		58,151		
14		Employee Meeting		44,698		
15		Employee Reimbursable Expense		52,518		
16		Express Mail		4		
17		Insurance		429,420		
18		Legal Retainers & Fees		371,917		
19		Meal Allowance		814		
20		Cash Donations		24,561		
21		Meals & Entertainment		39,542		
22		Moving Expense		1,660		
23		Industry Dues & Licenses		50,099		
24		Office Expenses		22,185		
25		Supplemental Insurance		973,081		
26		Permits & Filing Fees		9,573		
27		Postage		6,844		
28		Payroll		6,062,394		
29		Reimbursements		(1,026)		
30		Reference Materials		61,961		
31		Rental		2,064		
32		Seminars & Meeting Registrations		28,147		
33		Software Maintenance		157,640		
34		Telephone/Cell Expenses		67,497		
35		Training Material		15,207		
36		**Total MDU Resources Group, Inc.**		$10,098,741	1.8269%	

Company Name: Montana-Dakota Utilities Co. SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

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		Other Departments	* Various Corporate Overhead			
3		Expense	Allocation Factors, Cost of			
4		Payroll	Service Factors, Time	$6,132		
5		Automobile	Studies and /or Actual Costs	2,044		
6		Materials		2,004		
7		Office Expenses		5		
8		Miscellaneous		1,542		
9						
10		Transportation Department	* Various Corporate Overhead			
11		Clearing Accounts	Allocation Factors, Time Studies			
12		Office Expenses	and/or Actual Costs Incurred	136		
13						
14		Other Direct Charges	Actual Costs Incurred			
15		Utility/Merchandise Discounts		35,791		
16		Audit Costs		391,697		
17		Contract Services		484,906		
18		Auto		3,598		
19		Vehicle Maintenance		10,730		
20		Dues, Permits, and Filing Fees		4,078		
21		Misc Employee Benefits		51,397		
22		Computer/Software Support		373,935		
23		Electric Consumption		1,714,371		$1,385,181
24		Gas Consumption		45,342		31,063
25		Cost of Service		225,943		53,853
26		Region Billings		17,272		
27		Legal Fees		7,135		
28		Travel		10,334		
29		Communication Services		11,112		
30		Office Expense		14,158		
31		Bank Fees		13,951		
32		Training Registration		14,046		
33						
34		**Total Montana-Dakota Utilities Co.**		$3,441,659	0.6226%	$1,470,097
35						

Company Name: Montana-Dakota Utilities Co. SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price		(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	**WBI HOLDINGS, INC.**					
2						
3						
4						
5		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual Costs Incurred			
6		Federal & State Tax Liability Payments		($6,379,517)		
7		Miscellaneous Reimbursements		(88,077)		
8		**Total Other Transactions/Reimbursements**		($6,467,594)	-1.1700%	
9						
10		**Grand Total Affiliate Transactions**		$7,072,806	1.2795%	$1,470,097
11						
12						
13						
14		**Total WBI Holdings Operating Expenses for 2011 - Excludes Intersegment Eliminations**			$552,774,000	
15						

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

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	**MDU CONSTRUCTION**	MDU RESOURCES GROUP, INC.				
2	**SERVICES GROUP INC**	Corporate Overhead	* Various Corporate Overhead			
3		Audit Costs	Allocation Factors, Time	$9,892		
4		Advertising	Studies and/or Actual Costs	9,944		
5		Air Service	Incurred	8,400		
6		Automobile		955		
7		Bank Services		20,141		
8		Corporate Aircraft		6,175		
9		Consultant Fees		33,811		
10		Contract Services		53,606		
11		Computer Rental		306		
12		Directors Expenses		110,749		
13		Employee Benefits		9,555		
14		Employee Meeting		7,648		
15		Employee Reimbursable Expense		10,860		
16		Express Mail		1		
17		Insurance		73,538		
18		Legal Retainers & Fees		62,611		
19		Moving Allowance		285		
20		Meal Allowance		136		
21		Cash Donations		4,196		
22		Meals & Entertainment		7,051		
23		Industry Dues & Licenses		8,383		
24		Office Expenses		3,348		
25		Supplemental Insurance		158,990		
26		Permits & Filing Fees		1,654		
27		Postage		1,145		
28		Payroll		1,335,348		
29		Reimbursements		(614)		
30		Reference Materials		10,384		
31		Rent		114		
32		Seminars & Meeting Registrations		4,825		
33		Software Maintenance		22,675		
34		Telephone/Cell Expenses		5,990		
35		Training Material		2,298		
36		**Total MDU Resources Group, Inc.**		$1,984,400	0.2626%	

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

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**	Intercompany Settlements	Actual Costs Incurred			
3		Legal Fees		$132,420		
4		Audit		404,844		
5		Computer/Software Support		99,951		
6		Travel		5,687		
7		Cost of Service		98,843		$23,559
8		Employee Benefits		169,680		
9		Bank Fees		64,022		
10		Dues, Permits, and Filing Fees		15,884		
11		Payroll		2,050,399		
12		Office Expense		1,633		
13		Contract Services		106,259		
14						
15		**Total Montana-Dakota Utilities Co.**		$3,149,622	0.3863%	$23,559
16						
17		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual Costs Incurred			
18		Federal & State Tax Liability Payments		$12,673,832		
19		Miscellaneous Reimbursements		(161,197)		
20						
21		**Total Other Transactions/Reimbursements**		$12,512,635	1.5348%	
22						
23		**Grand Total Affiliate Transactions**		$17,646,657	2.1646%	$23,559
24						
25		**Total MDU Construction Services Group, Inc. Operating Expenses for 2011**				
26		**Excludes Intersegment Eliminations**			$815,245,000	
27						

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AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

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 UTIILITIES CO.				
2	**RESOURCES**	Other Direct Charges	Actual costs incurred			
3		Audit Costs		$10,836		
4		Dues, Permits, and Filing Fees		375		
5		Bank Fees		2,296		
6						
7		Intercompany Settlements	Actual costs incurred			
8		Filing Fees		875		
9		Office Expense		243		
10						
11		**Total Montana-Dakota Utilities Co.**		$14,625	3.5934%	
12						
13		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual costs incurred			
14		Federal & State Tax Liability Payments		($479,318)		
15		Miscellaneous Reimbursements		(4)		
16						
17		**Total Other Transactions/Reimbursements**		($479,322)	-117.7695%	
18						
19		**Grand Total Affiliate Transactions**		($464,697)	-114.1762%	
20						
21		**Total Centennial Energy Resources Operating Expenses for 2011**			$407,000	
22		**Excludes Intersegment Eliminations**				
23						

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AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	**CENTENNIAL HOLDINGS**	MONTANA-DAKOTA UTILITIES CO.				
2	**CAPITAL CORP. AND**	Direct and Intercompany Charges	Actual costs incurred			
3	**FUTURESOURCE**	Dues, Permits, and Filing Fees		$532		
4		Computer/Software Support		17,256		
5		Bank Fees		2,258		
6		Materials		163		
7		Office Expense		3,912		
8		Electric Consumption		156,212		
9		Gas Consumption		13,309		
10		Payroll		374,526		
11		Miscellaneous		86		
12						
13		**Total Montana-Dakota Utilities Co.**		$568,254	9.4473%	
14						
15		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual costs incurred			
16		Insurance		$119		
17		Miscellaneous Reimbursements		(6,225)		
18		Federal & State Tax Liability Payments		(1,724,608)		
19						
20		**Total Other Transactions/Reimbursements**		($1,730,714)	-28.7733%	
21						
22		**Grand Total Affiliate Transactions**		($1,162,460)	-19.3260%	
23						
24		**Total CHCC Operating Expenses for 2011**			$6,015,000	
25		**Excludes Intersegment Eliminations**				
26						

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

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	**MDU ENERGY**	MDU RESOURCES GROUP, INC.				
2	**CAPITAL** **	Corporate Overhead	* Various Corporate Overhead			
3		Audit Costs	Allocation Factors, Time	$33,969		
4		Advertising	Studies and/or Actual Costs	75,711		
5		Air Service	Incurred	15,460		
6		Automobile		3,041		
7		Bank Services		69,054		
8		Corporate Aircraft		21,100		
9		Consultant Fees		115,893		
10		Contract Services		255,792		
11		Computer Rental		1,045		
12		Directors Expenses		379,581		
13		Employee Benefits		33,407		
14		Employee Meeting		25,945		
15		Employee Reimbursable Expense		28,849		
16		Express Mail		2		
17		Insurance		243,400		
18		Legal Retainers & Fees		214,315		
19		Meal Allowance		468		
20		Cash Donations		14,246		
21		Meals & Entertainment		20,766		
22		Moving Allowance		965		
23		Industry Dues & Licenses		28,872		
24		Office Expenses		13,512		
25		Supplemental Insurance		550,937		
26		Permits & Filing Fees		5,565		
27		Postage		3,931		
28		Payroll		3,809,842		
29		Reimbursements		(3,890)		
30		Reference Materials		35,612		
31		Rental		386		
32		Seminars & Meeting Registrations		16,168		
33		Software Maintenance		93,427		
34		Telephone		26,598		
35		Training Material		9,234		
36		**Total MDU Resources Group, Inc.**		$6,143,203	1.1163%	

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	**MDU ENERGY**	MONTANA-DAKOTA UTILITIES CO.				
2	**CAPITAL** **	Customer Service/Credit & Collections	* Various Corporate Overhead			
3		Automobile	Allocation Factors, Cost of	$573		
4		Contract Services	Service Factors, Time Studies	4,452		
5		Employee Benefits	and/or Actual Costs Incurred	171		
6		Miscellaneous		2,088		
7		Office Expense		13,667		
8		Payroll		497,035		
9		Travel		1,284		
10						
11		Executive Departments	* Various Corporate Overhead			
12		Automobile	Allocation Factors, Cost of	22		
13		Contract Services	Service Factors, Time Studies	4,000		
14		Employee Benefits	and/or Actual Costs Incurred	14,704		
15		Miscellaneous		462		
16		Office Expense		2,012		
17		Payroll		709,719		
18		Travel		42,812		
19						
20		General & Administrative	* Various Corporate Overhead			
21		Office Expense	Allocation Factors, Cost of	2		
22		Payroll	Service Factors, Time Studies	8,565		
23		Travel	and/or Actual Costs Incurred	1,037		
24						
25		Information Systems	* Various Corporate Overhead			
26		Material	Allocation Factors, Cost of	956		
27		Miscellaneous	Service Factors, Time Studies	4,531		
28		Office Expense	and/or Actual Costs Incurred	5,037		
29		Payroll		350,389		
30		Travel		5,467		
31						
32		Other Miscellaneous Departments	* Various Corporate Overhead			
33		Payroll	Allocation Factors, Cost of Service	16,641		
34		Travel	Factors, Time Studies and/or	2,878		
35			Actual Costs Incurred			

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	**MDU ENERGY**	MONTANA-DAKOTA UTILITIES CO.				
2	**CAPITAL** **	Payroll & HR	* Various Corporate Overhead			
3		Employee Benefits	Allocation Factors, Cost of Service	6,477		
4		Payroll	Factors, Time Studies and/or	7,727		
5						
6		Other Direct Charges	Actual costs incurred			
7		Audit		108,273		
8		Bank Fees		3,254		
9		Communications		52,422		
10		Computer Equipment/Software		125,181		
11		Contract Services		92,047		
12		Employee Benefits		(14,114)		
13		Filing Fees		1,774		
14		Industry Dues		212,771		
15		Material		8,569		
16		Miscellaneous		96		
17		Travel		19,236		
18		Vehicle Maintenance		7,166		
19						
20		Intercompany Settlements				
21		O&M	Actual costs incurred			
22		Advertising		5,122		
23		Auto		247		
24		Contract Services		433,166		
25		Cost of Service		1,515,157		$361,136
26		Employee Benefits		43,592		
27		Material		32,348		
28		Miscellaneous		54,767		
29		Office Expense		211,478		
30		Payroll		8,684,075		
31		Supplemental Insurance		166,304		
32		Software Maintenance		420,773		
33		Travel		233,677		
34						
35						

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	**MDU ENERGY**	MONTANA-DAKOTA UTILITIES CO.				
2	**CAPITAL ****	Intercompany Settlements				
3		Other	Actual costs incurred			
4		Audit		269,000		
5		Auto O&M		35,118		
6		LTIP		5,596		
7		MII		270,554		
8		Misc		34,366		
9		Payflex		(71,604)		
10						
11		Capital	Actual costs incurred			
12		Auto		184		
13		Contract Services		100,255		
14		Materials		114,461		
15		Office Expense		7,508		
16		Payroll		154,086		
17		Software Licenses		13,775		
18		Travel		45,556		
19		Utility Group Project Allocation		5,450,985		
20						
21		**Total Montana-Dakota Utiilities Co.**		$20,549,929	3.7341%	$361,136
22						
23		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual costs incurred			
24		Federal & State Tax Liability Payments		($3,669,865)		
25		Miscellaneous Reimbursements		(108,096)		
26						
27		**Total Other Transactions/Reimbursements**		($3,777,961)	-0.6865%	
28						
29		**Grand Total Affiliate Transactions**		$22,915,171	4.1638%	$361,136
30						
31		**Total MDU Energy Capital Operating Expenses for 2011**			$550,337,000	
32		**Excludes Intersegment Eliminations**				
33						
34						

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

MDU ENERGY CAPITAL

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

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

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	**CENTENNIAL ENERGY**	MONTANA-DAKOTA UTILITIES CO.				
2	**HOLDING INC**					
3		Other Direct Charges	Actual costs incurred			
4		Audit Costs		$124,450		
5		Dues, Permits, and Filing Fees		125		
6		Contract Services		64,520		
7		Bank Fees		2,338		
8		Miscellaneous		55		
9						
10		**Total Montana-Dakota Utilities Co.**		$191,488		
11						
12		**Grand Total Affiliate Transactions**		$191,488		
13						
14						
15						
16						

MONTANA UTILITY INCOME STATEMENT

Year: 2011

	Account Number & Title		Last Year	This Year	% Change
1	400	Operating Revenues	$46,721,323	$51,564,935	10.37%
2					
3		Operating Expenses			
4	401	Operation Expenses	$26,238,000	$28,330,472	7.97%
5	402	Maintenance Expense	3,682,201	3,925,907	6.62%
6	403	Depreciation Expense	5,327,388	5,980,478	12.26%
7	404-405	Amortization of Electric Plant	281,109	247,920	-11.81%
8	406	Amort. of Plant Acquisition Adjustments	56,526	54,939	-2.81%
9	407	Amort. of Property Losses, Unrecovered Plant			
10		& Regulatory Study Costs			
11	408.1	Taxes Other Than Income Taxes	3,333,645	3,401,867	2.05%
12	409.1	Income Taxes - Federal	(2,484,727)	(3,299,248)	-32.78%
13		- Other	(805,175)	(412,692)	48.75%
14	410.1	Provision for Deferred Income Taxes	3,838,594	4,325,846	12.69%
15	411.1	(Less) Provision for Def. Inc. Taxes - Cr.	837,688	530,383	-36.68%
16	411.4	Investment Tax Credit Adjustments			
17	411.6	(Less) Gains from Disposition of Utility Plant			
18	411.7	Losses from Disposition of Utility Plant			
19					
20		**TOTAL Utility Operating Expenses**	$40,305,249	$43,085,872	6.90%
21		**NET UTILITY OPERATING INCOME**	$6,416,074	$8,479,063	32.15%

MONTANA REVENUES

SCHEDULE 9

	Account Number & Title		Last Year	This Year	% Change
1		Sales of Electricity			
2	440	Residen	$13,364,669	$14,938,802	11.78%
3	442	Commei	7,956,486	8,811,963	10.75%
4		Commei	20,579,717	23,496,466	14.17%
5	444	Public S	790,290	841,263	6.45%
6	445	Other Sa	389,026	416,506	7.06%
7	446	Sales to			
8	448	Interdep			
9		Net Unb	513,299	(81,725)	-115.92%
10		**TOTAL Sal**	$43,593,487	$48,423,275	11.08%
11	447	Sales for Resale	1,172,064	940,078	-19.79%
12					
13		**TOTAL Sales of Electricity**	$44,765,551	$49,363,353	10.27%
14	449.1	(Less) Provision for Rate Refunds			
15					
16		**TOTAL Revenue Net of Provision for Refunds**	$44,765,551	$49,363,353	10.27%
17		Other Operating Revenues			
18	450	Forfeited Discounts & Late Payment Revenues			
19	451	Miscellaneous Service Revenues	$7,141	$15,160	112.30%
20	453	Sales of Water & Water Power			
21	454	Rent From Electric Property	1,133,539	1,105,519	-2.47%
22	455	Interdepartmental Rents			
23	456	Other Electric Revenues	815,092	1,080,903	32.61%
24					
25		**TOTAL Other Operating Revenues**	$1,955,772	$2,201,582	12.57%
26		**Total Electric Operating Revenues**	$46,721,323	$51,564,935	10.37%

Unbilled reflects 466 correction Adj last yr to this yr.

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2011

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses			
2				
3	Steam Power Generation			
4	Operation			
5	500 Operation Supervision & Engineering	$502,123	$406,098	-19.12%
6	501 Fuel	12,087,681	12,031,695	-0.46%
7	502 Steam Expenses	1,033,888	1,125,683	8.88%
8	503 Steam from Other Sources			
9	504 (Less) Steam Transferred - Cr.			
10	505 Electric Expenses	345,571	400,305	15.84%
11	506 Miscellaneous Steam Power Expenses	599,501	580,717	-3.13%
12	507 Rents	144	42	-70.83%
13				
14	TOTAL Operation - Steam	14,568,908	14,544,540	-0.17%
15				
16	Maintenance			
17	510 Maintenance Supervision & Engineering	206,321	199,127	-3.49%
18	511 Maintenance of Structures	142,819	163,803	14.69%
19	512 Maintenance of Boiler Plant	1,175,459	1,218,337	3.65%
20	513 Maintenance of Electric Plant	248,921	234,711	-5.71%
21	514 Maintenance of Miscellaneous Steam Plant	277,585	317,828	14.50%
22				
23	TOTAL Maintenance - Steam	2,051,105	2,133,806	4.03%
24				
25	**TOTAL Steam Power Production Expenses**	$16,620,013	$16,678,346	0.35%
26				
27	Nuclear Power Generation			
28	Operation			
29	517 Operation Supervision & Engineering			
30	518 Nuclear Fuel Expense			
31	519 Coolants & Water			
32	520 Steam Expenses			
33	521 Steam from Other Sources		NOT	
34	522 (Less) Steam Transferred - Cr.		APPLICABLE	
35	523 Electric Expenses			
36	524 Miscellaneous Nuclear Power Expenses			
37	525 Rents			
38				
39	TOTAL Operation - Nuclear			
40				
41	Maintenance			
42	528 Maintenance Supervision & Engineering			
43	529 Maintenance of Structures			
44	530 Maintenance of Reactor Plant Equipment		NOT	
45	531 Maintenance of Electric Plant		APPLICABLE	
46	532 Maintenance of Miscellaneous Nuclear Plant			
47				
48	TOTAL Maintenance - Nuclear			
49				
50	**TOTAL Nuclear Power Production Expenses**			

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2011

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses -continued			
2	Hydraulic Power Generation			
3	Operation			
4	535 Operation Supervision & Engineering			
5	536 Water for Power			
6	537 Hydraulic Expenses		NOT	
7	538 Electric Expenses		APPLICABLE	
8	539 Miscellaneous Hydraulic Power Gen. Expenses			
9	540 Rents			
10				
11	TOTAL Operation - Hydraulic			
12				
13	Maintenance			
14	541 Maintenance Supervision & Engineering			
15	542 Maintenance of Structures		NOT	
16	543 Maint. of Reservoirs, Dams & Waterways		APPLICABLE	
17	544 Maintenance of Electric Plant			
18	545 Maintenance of Miscellaneous Hydro Plant			
19				
20	TOTAL Maintenance - Hydraulic			
21				
22	**TOTAL Hydraulic Power Production Expenses**			
23				
24	Other Power Generation			
25	Operation			
26	546 Operation Supervision & Engineering	$28,508	$28,714	0.72%
27	547 Fuel	308,950	426,739	38.13%
28	548 Generation Expenses	116,750	148,309	27.03%
29	549 Miscellaneous Other Power Gen. Expenses	83,384	78,503	-5.85%
30	550 Rents	12,878	25,482	97.87%
31				
32	TOTAL Operation - Other	550,470	707,747	28.57%
33				
34	Maintenance			
35	551 Maintenance Supervision & Engineering	13,683	14,324	4.68%
36	552 Maintenance of Structures	7,028	1,186	-83.12%
37	553 Maintenance of Generating & Electric Plant	63,591	85,704	34.77%
38	554 Maintenance of Misc. Other Power Gen. Plant	2	64	3100.00%
39				
40	TOTAL Maintenance - Other	84,304	101,278	20.13%
41				
42	**TOTAL Other Power Production Expenses**	$634,774	$809,025	27.45%
43				
44	Other Power Supply Expenses			
45	555 Purchased Power	$3,816,099	$5,212,934	36.60%
46	556 System Control & Load Dispatching	302,125	318,747	5.50%
47	557 Other Expenses			
48				
49	TOTAL Other Power Supply Expenses	$4,118,224	$5,531,681	34.32%
50				
51	**TOTAL Power Production Expenses**	$21,373,011	$23,019,052	7.70%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2011

	Account Number & Title		Last Year	This Year	% Change
1	Transmission Expenses				
2	Operation				
3	560	Operation Supervision & Engineering	$352,450	$249,627	-29.17%
4	561	Load Dispatching	358,812	373,651	4.14%
5	562	Station Expenses	159,993	134,806	-15.74%
6	563	Overhead Line Expenses	30,453	37,267	22.38%
7	564	Underground Line Expenses			
8	565	Transmission of Electricity by Others	19,354	226,933	1072.54%
9	566	Miscellaneous Transmission Expenses	31,376	27,346	-12.84%
10	567	Rents	170,461	167,486	-1.75%
11	575	Day-Ahead and Real-Time Market Administration	121,428	111,694	-8.02%
12					
13	TOTAL Operation - Transmission		1,244,327	1,328,810	6.79%
14	Maintenance				
15	568	Maintenance Supervision & Engineering	12,528	13,758	9.82%
16	569	Maintenance of Structures			
17	570	Maintenance of Station Equipment	99,524	179,466	80.32%
18	571	Maintenance of Overhead Lines	215,632	158,648	-26.43%
19	572	Maintenance of Underground Lines			
20	573	Maintenance of Misc. Transmission Plant			
21					
22	TOTAL Maintenance - Transmission		327,684	351,872	7.38%
23					
24	**TOTAL Transmission Expenses**		$1,572,011	$1,680,682	6.91%
25					
26	Distribution Expenses				
27	Operation				
28	580	Operation Supervision & Engineering	$224,202	$249,281	11.19%
29	581	Load Dispatching			
30	582	Station Expenses	53,127	92,413	73.95%
31	583	Overhead Line Expenses	115,474	44,499	-61.46%
32	584	Underground Line Expenses	144,552	161,322	11.60%
33	585	Street Lighting & Signal System Expenses	6,730	10,073	49.67%
34	586	Meter Expenses	108,684	128,094	17.86%
35	587	Customer Installations Expenses	75,240	59,807	-20.51%
36	588	Miscellaneous Distribution Expenses	513,146	548,209	6.83%
37	589	Rents	28,399	25,398	-10.57%
38					
39	TOTAL Operation - Distribution		1,269,554	1,319,096	3.90%
40	Maintenance				
41	590	Maintenance Supervision & Engineering	106,333	120,934	13.73%
42	591	Maintenance of Structures			
43	592	Maintenance of Station Equipment	14,741	6,254	-57.57%
44	593	Maintenance of Overhead Lines	599,259	625,611	4.40%
45	594	Maintenance of Underground Lines	150,595	206,045	36.82%
46	595	Maintenance of Line Transformers	40,242	50,510	25.52%
47	596	Maintenance of Street Lighting, Signal Systems	48,202	43,646	-9.45%
48	597	Maintenance of Meters	16,884	23,131	37.00%
49	598	Maintenance of Miscellaneous Dist. Plant	122,436	154,517	26.20%
50					
51	TOTAL Maintenance - Distribution		1,098,692	1,230,648	12.01%
52					
53	**TOTAL Distribution Expenses**		$2,368,246	$2,549,744	7.66%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2011

	Account Number & Title	Last Year	This Year	% Change
1	Customer Accounts Expenses			
2	Operation			
3	901 Supervision	$31,690	$25,589	-19.25%
4	902 Meter Reading Expenses	156,143	150,470	-3.63%
5	903 Customer Records & Collection Expenses	390,288	427,174	9.45%
6	904 Uncollectible Accounts Expenses	48,380	72,517	49.89%
7	905 Miscellaneous Customer Accounts Expenses	29,019	27,959	-3.65%
8				
9	TOTAL Customer Accounts Expenses	$655,520	$703,709	7.35%
10				
11	Customer Service & Information Expenses			
12	Operation			
13	907 Supervision	$10,642	$10,814	1.62%
14	908 Customer Assistance Expenses	(6,614)	4,991	175.46%
15	909 Informational & Instructional Adv. Expenses	2,690	8,725	224.35%
16	910 Miscellaneous Customer Service & Info. Exp.	29	7	-75.86%
17				
18	TOTAL Customer Service & Info Expenses	$6,747	$24,537	263.67%
19				
20	Sales Expenses			
21	Operation			
22	911 Supervision	$2,532	$1,945	-23.18%
23	912 Demonstrating & Selling Expenses	14,808	13,740	-7.21%
24	913 Advertising Expenses	1,174	2,294	95.40%
25	916 Miscellaneous Sales Expenses	6,008	5,254	-12.55%
26				
27	TOTAL Sales Expenses	$24,522	$23,233	-5.26%
28				
29	Administrative & General Expenses			
30	Operation			
31	920 Administrative & General Salaries	$1,139,919	$994,690	-12.74%
32	921 Office Supplies & Expenses	621,285	596,826	-3.94%
33	922 (Less) Administrative Expenses Transferred - Cr.			
34	923 Outside Services Employed	182,362	81,966	-55.05%
35	924 Property Insurance	168,751	133,200	-21.07%
36	925 Injuries & Damages	261,380	210,727	-19.38%
37	926 Employee Pensions & Benefits	1,073,338	1,746,185	62.69%
38	927 Franchise Requirements			
39	928 Regulatory Commission Expenses	173,308	212,825	22.80%
40	929 (Less) Duplicate Charges - Cr.			
41	930.1 General Advertising Expenses	7,664	14,175	84.96%
42	930.2 Miscellaneous General Expenses	54,865	82,213	49.85%
43	931 Rents	116,856	74,312	-36.41%
44				
45	TOTAL Operation - Admin. & General	3,799,728	4,147,119	9.14%
46	Maintenance			
47	935 Maintenance of General Plant	120,416	108,303	-10.06%
48				
49	**TOTAL Administrative & General Expenses**	$3,920,144	$4,255,422	8.55%
50				
51	**TOTAL Operation & Maintenance Expenses**	$29,920,201	$32,256,379	7.81%

MONTANA TAXES OTHER THAN INCOME

Year: 2011

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes	$498,617	$441,026	-11.55%
2	Secretary of State	386	339	-12.18%
3	Highway Use Tax	476	488	2.52%
4	Montana Consumer Counsel	21,707	54,485	151.00%
5	Montana PSC	133,100	177,707	33.51%
6	Montana Electric	53,740	56,405	4.96%
7	Coal Conversion	276,616	277,395	0.28%
8	Delaware Franchise	25,027	22,635	-9.56%
9	Property Taxes	2,323,976	2,371,387	2.04%
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50	**TOTAL MT Taxes Other Than Income**	$3,333,645	$3,401,867	2.05%

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

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - ELECTRIC

Year: 2011

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	ACS Construction	Plant Update & Repair	$631,764		0.00%
2					
3	Aerotec LLC	Aerial Mapping of Transmission Lines	182,108	$43,834	24.07%
4					
5	AFPI	Annual Report Preparation	141,890	2,683	1.89%
6					
7	American Gas Association	Industrial Membership	99,847		0.00%
8					
9	API Construction Co.	Contractor Services - Power Plant	113,992	27,438	24.07%
10					
11	Atlantic Plant Services	Contract Services - Environmental	95,495	22,986	24.07%
12					
13	B & B Foundation Service Inc.	Construction Service	154,705	2,493	1.61%
14					
15	Barr Engineering Company	Engineering Services	196,927	47,318	24.03%
16					
17	Benco Equipment Co.	Vehicle Maintenance	224,033	54	0.02%
18					
19	Bismarck-Mandan Area	Promotional-MDU Resources	251,634	4,759	1.89%
20	Chamber of Commerce	Bowl Naming Rights			
21	Blue Heron	Consulting Services	1,351,467	83,442	6.17%
22					
23	Brink Construction Inc.	Contract Services - Storm Replacement	2,260,227	400,846	17.73%
24					
25	Broadridge	Contract Services - Shareholder	132,602	2,508	1.89%
26					
27	Bullinger Tree Services	Tree Trimming	363,080	13,456	3.71%
28					
29	Butler Machinery Co.	Equipment Maintenance	85,463	20,571	24.07%
30					
31	Central Trenching	Contract Services - Trenching	270,025		0.00%
32					
33	CGI Technologies & Solutions	Replace Mobile Workforce Software	134,843	7,657	5.68%
34					
35	Chief Construction	Construction Service	755,342	494	0.07%
36					
37	Cisco Systems Capital Corp.	Software Maintenance	121,222	1,368	1.13%
38					
39	Clean Harbors Environmental	Replace U1-Boiling Bank Tubes-Heskett	118,185	25,695	21.74%
40	Services				
41	Cohen, Tauber, Spievack &	Legal Services	341,674	6,005	1.76%
42	Wagner, PC				
43	Connecting Point	Computer Services & Software Maint.	78,522	8,449	10.76%
44					
45	Countless Energy Inc.	Gas Meter Reading	76,773		0.00%
46					
47	D&D Roofing LLP	Replace Bismarck Service Center Roof	262,419		0.00%
48					
49	Dakota Fence Co.	Contract Services - Fencing	86,044	13,675	15.89%
50					

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - ELECTRIC Year: 2011

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Dakota Tree Service	Tree Trimming	160,363	8,124	5.07%
2					
3	Deloitte & Touche LLP	Auditing & Consulting Services	923,638	37,565	4.07%
4					
5	Denny's Electric Motor Repair	Line Extension & Pipe Extensions	155,494	31,440	20.22%
6					
7	Dewey & LeBoeuf	Legal Services	759,144	23,654	3.12%
8					
9	Dorsey & Whitney, LLP	Legal Services	104,208	16,826	16.15%
10					
11	Edison Electric Institute	Industrial Membership	100,300	20,854	20.79%
12					
13	EP2M	Consulting Services	1,498,175	92,500	6.17%
14					
15	Eide Ford Mercury Lincoln Inc.	Auto Maintenance	80,469		0.00%
16					
17	Environmental Plant Services	Contract Services - Environmental	77,850	18,739	24.07%
18					
19	Fischer Contracting	Construction Services - Gas	318,904		0.00%
20					
21	Franz Construction Inc.	Contract Services - Power Plant	460,254	118,443	25.73%
22					
23	Forrester, Gary	Lobbying & Promotion	104,082	1,968	1.89%
24					
25	GE Energy Services	Contractor Services - Power Plant	227,895	54,855	24.07%
26					
27	Gagnon Inc.	Contractor Services - Heskett Station	518,516	124,809	24.07%
28					
29	General Electric International	Contractor Services	346,955	88,668	25.56%
30					
31	Govert Powerline Services	Contractor Services - Install Lighting	288,212	3,568	1.24%
32		Arresters			
33	Hardy Construction	Contractor Services - Billings Landfill	203,273		0.00%
34					
35	HDR Engineering Inc.	Engineering Services	729,906	175,691	24.07%
36					
37	High Point Networks	Contractor Services	82,169	6,431	7.83%
38					
39	Highmark, Inc.	Construction Services	1,877,065	322,132	17.16%
40					
41	Honeywell Industry Solutions	Equipment Installation	100,138	24,104	24.07%
42					
43	Hughes, Kellner, Sullivan & Alke	Legal Services	77,704	13,033	16.77%
44	PLLP				
45	Industrial Contractors Inc.	Contract Services - Power Plant	489,732	115,101	23.50%
46					
47	Infrasource	Underground Gas Line Installation	2,130,475		0.00%
48					
49	Intermountain Tree Expert Co.	Tree Trimming	137,831		0.00%
50					

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - ELECTRIC

Year: 2011

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Itron Inc.	Contractor Services - Software Maint.	188,697	11,477	6.08%
2					
3	J.B. Construction Inc.	Contractor Services - Line Replacement	266,750	64,208	24.07%
4					
5	Kappel Tree Service, LLP	Tree Trimming	252,872	151,173	59.78%
6					
7	LFG Technologies Develop. LLC	Contractor Services - Billings Landfill	150,136		0.00%
8					
9	McDermott, Will & Emery LLP	Legal Services	76,332	1,735	2.27%
10					
11	MCM General Contractors, Inc.	Construction Services	512,586		0.00%
12					
13	Microsoft Licensing GP	Software Maintenance	302,151	12,669	4.19%
14					
15	Midwest ISO	Contractor Services	315,537	66,194	20.98%
16					
17	Millcreek Engineering Company	Engineering Services	277,333	66,755	24.07%
18					
19	Moorhead Machinery & Boiler	Contractor Services - Power Plant	1,507,407	362,839	24.07%
20					
21	New York Life	Consulting Services	190,566	7,281	3.82%
22					
23	Norby Inc.	Trucking - Sidney	77,040	21,170	27.48%
24					
25	North American Electric	NERC & MRO Region Assessment	80,088	19,030	23.76%
26					
27	NYSE Market Inc.	Financial Services	177,598	3,359	1.89%
28					
29	One Call Locaters	Line Location Services	1,093,001	18,316	1.68%
30					
31	Open Systems International, Inc.	EMS Upgrade - Replacement	2,344,626	501,693	21.40%
32					
33	Oracle Corporation	Software Maintenance	375,768	24,794	6.60%
34					
35	Ormat Nevada Inc.	Energy Convertor Maint. Agreement	206,694	49,752	24.07%
36					
37	Otter Tail Power Co.	Transmission Line Repair	77,199	18,582	24.07%
38					
39	Pearce, Harry J.	Active Directors Fees	130,000	2,459	1.89%
40					
41	Power Generations Service Inc.	Contract Services - Power Plants	171,137	41,193	24.07%
42					
43	Progressive Maintenance	Custodial Service	134,747	19,261	14.29%
44					
45	Prosource Tech Inc.	Contract Services - Environmental	536,359	25,389	4.73%
46					
47	PSC Industrial Outsourcing	Contractor Services - Power Plant	742,662	180,819	24.35%
48					
49	Q3 Contracting	Construction Services	157,426		0.00%
50					

Company Name: Montana-Dakota Utilities Co. SCHEDULE 12

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - ELECTRIC

Year: 2011

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Rocky Mountain Contractors, Inc.	Contractor Services	234,612		0.00%
2					
3	Southern Cross Corporation	Construction Services	225,826		0.00%
4					
5	Spherion Corporation	Temp Service	332,821	46,008	13.82%
6					
7	SQLSoft Consulting Group	Consulting Services - Replace CIS	79,625	4,916	6.17%
8					
9	Standard & Poors	Financial Services	159,680	6,019	3.77%
10					
11	State Line Contractors Inc.	Constructions Services	376,699		0.00%
12					
13	Telvent USA Corporation	Software Development	101,377	5,415	5.34%
14					
15	Timberline Construction Inc.	Contractors Services-Transmission Lines	657,957	40,601	6.17%
16					
17	Total Corrosion Solutions Inc.	Contractor Services	77,372	54,606	70.58%
18					
19	Transystems LLC	Haul Charges	75,230	21,695	28.84%
20					
21	Treasury Management Services	Banking Services	298,699	25,591	8.57%
22					
23	Ulmer Tree Service	Tree Trimming Service	168,474		0.00%
24					
25	USIC Locating Services, Inc.	Line Locating	136,860		0.00%
26					
27	Ultilimatic LLC	Install Gas ERTS	166,085		0.00%
28					
29	Utility Partners, Inc.	Maintenance Renewal	85,800	6,159	7.18%
30					
31	Utility Shareholders of ND	Organizational Dues	97,500		0.00%
32					
33	Van Horn Media	Advertising	92,192	2,192	2.38%
34					
35	Ventyx Energy LLC	Software Maintenance	95,010	22,869	24.07%
36					
37	Wells Fargo Shareowners Services	Stock Transfer Agent	283,244	5,357	1.89%
38					
39	Western Engineered Solutions	Contract Services - Heskett	121,997	29,365	24.07%
40					
41	Workforce Services	Vehicle Maintenance	181,112		0.00%
42					
43					
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50					
51	TOTAL Payments for Services		$34,875,919	$3,975,177	11.40%

Company Name: Montana-Dakota Utilities Co. SCHEDULE 13

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2011

	Description	Total Company	Montana	% Montana
1	Contributions to Candidates by PAC	$15,779	$6,850	43.41%
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43	**TOTAL Contributions**	$15,779	$6,850	43.41%

Pension Costs

Year: 2011

1	Plan Name MDU Resources Group, Inc. Master Pension Plan Trust			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? Traditional Unit Credit	IRS Code: 1A		
4	Annual Contribution by Employer: 13,757,133	Is the Plan Over Funded? No		
5				

	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**	(000's)	(000's)	
7	Benefit obligation at beginning of year	$230,271	$209,621	9.85%
8	Service cost	1,056	1,826	-42.17%
9	Interest cost	11,446	11,745	-2.55%
10	Plan participants' contributions	-	-	0.00%
11	Amendments	-	-	0.00%
12	Actuarial (Gain) Loss	35,719	20,971	70.33%
13	Curtailment gain	(13,939)	-	N/A
14	Benefits paid	(14,730)	(13,892)	-6.03%
15	Benefit obligation at end of year	$249,823	$230,271	8.49%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$164,852	$152,426	8.15%
18	Actual return on plan assets	(2,595)	22,446	-111.56%
19	Employer contribution	13,757	3,872	255.29%
20	Plan participants' contributions	-	-	0.00%
21	Benefits paid	(14,730)	(13,892)	-6.03%
22	Fair value of plan assets at end of year	$161,284	$164,852	-2.16%
23	**Funded Status**	($88,539)	($65,419)	-35.34%
24	Unrecognized net actuarial loss	-	-	0.00%
25	Unrecognized prior service cost	-	-	0.00%
26	Unrecognized net transition obligation	-	-	0.00%
27	Accrued benefit cost	($88,539)	($65,419)	-35.34%
28				
29	**Weighted-Average Assumptions as of Year End**			
30	Discount rate	4.16	5.26	-20.91%
31	Expected return on plan assets	7.75	7.75	0.00%
32	Rate of compensation increase	-	4.00	-100.00%
33				
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	$1,056	$1,826	-42.17%
36	Interest cost	11,446	11,745	-2.55%
37	Expected return on plan assets	(13,712)	(14,414)	4.87%
38	Amortization of prior service cost	130	265	-50.94%
39	Recognized net actuarial gain	1,473	573	157.07%
40	Curtailment loss	1,218	-	N/A
41	Net periodic benefit cost	$1,611	($5)	32320.00%
42				
43	**Montana Intrastate Costs:**			
44	Pension costs	$1,611	($5)	32320.00%
45	Pension costs capitalized	385	137	181.02%
46	Accumulated pension asset (liability) at year end	($88,539)	($65,419)	-35.34%
47	**Number of Company Employees:**			
48	Covered by the plan	1,766	1,818	-2.86%
49	Not covered by the plan	503	436	15.37%
50	Active	715	762	-6.17%
51	Retired	954	964	-1.04%
52	Deferred vested terminated	97	92	5.43%

Other Post Employment Benefits (OPEBS)

Year: 2011

	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	4.12	5.20	-20.77%
8	Expected return on plan assets	6.75	6.75	0.00%
9	Medical cost inflation rate	6.00	6.00	0.00%
10	Actuarial cost method	Projected unit credit	Projected unit credit	
11	Rate of compensation increase	N/A	N/A	
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13	**VEBA**			
14	**Describe any Changes to the Benefit Plan:**			
15				
16				
	TOTAL COMPANY			
17	**Change in Benefit Obligation**	(000's)	(000's)	
18	Benefit obligation at beginning of year	$45,547	$44,848	1.56%
19	Service cost	746	680	9.71%
20	Interest cost	2,406	2,412	-0.25%
21	Plan participants' contributions	1,710	1,645	3.95%
22	Amendments	-	-	0.00%
23	Actuarial (Gain) Loss	10,734	667	1509.30%
24	Acquisition	-	-	0.00%
25	Benefits paid	(3,982)	(4,705)	15.37%
26	Benefit obligation at end of year	$57,161	$45,547	25.50%
27	**Change in Plan Assets**			
28	Fair value of plan assets at beginning of year	$40,183	$37,973	5.82%
29	Actual return on plan assets	(506)	4,079	-112.41%
30	Acquisition	-	-	0.00%
31	Employer contribution	1,570	1,191	31.82%
32	Plan participants' contributions	1,710	1,645	3.95%
33	Benefits paid	(3,982)	(4,705)	15.37%
34	Fair value of plan assets at end of year	$38,975	$40,183	-3.01%
35	**Funded Status**	($18,186)	($5,364)	-239.04%
36	Unrecognized net actuarial loss	-	-	0.00%
37	Unrecognized prior service cost	-	-	0.00%
38	Unrecognized transition obligation	-	-	0.00%
39	Accrued benefit cost	($18,186)	($5,364)	-239.04%
40	**Components of Net Periodic Benefit Costs**			
41	Service cost	$746	$680	9.71%
42	Interest cost	2,406	2,412	-0.25%
43	Expected return on plan assets	(2,974)	(3,302)	9.93%
44	Amortization of prior service cost	(294)	(295)	0.34%
45	Recognized net acturial gain	-	-	0.00%
46	Transition amount amortization	1,671	1,664	0.42%
47	Net periodic benefit cost	$1,555	$1,159	34.17%
48	**Accumulated Post Retirement Benefit Obligation**			
49	Amount funded through VEBA	$3,280	$2,836	15.66%
50	Amount funded through 401(h)			
51	Amount funded through Other ______________			
52	TOTAL	$3,280	$2,836	15.66%
53	Amount that was tax deductible - VEBA	$1,570 (1)	$1,191	31.82%
54	Amount that was tax deductible - 401(h)			
55	Amount that was tax deductible - Other __________			
56	TOTAL	$1,570	$1,191	31.82%

(1) Estimated

Company Name: Montana-Dakota Utilities Co. SCHEDULE 15

Other Post Employment Benefits (OPEBS) Continued

Year: 2011

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the plan	1,723	1,801	-4.33%
3	Not covered by the plan	35	36	-2.78%
4	Active	934	1,010	-7.52%
5	Retired	639	643	-0.62%
6	Spouses/dependants covered by the plan	150	148	1.35%
7	**Montana**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year			
10	Service cost	NOT APPLICABLE		
11	Interest cost			
12	Plan participants' contributions			
13	Amendments			
14	Actuarial gain			
15	Acquisition			
16	Benefits paid			
17	Benefit obligation at end of year			
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year			
20	Actual return on plan assets			
21	Acquisition	NOT APPLICABLE		
22	Employer contribution			
23	Plan participants' contributions			
24	Benefits paid			
25	Fair value of plan assets at end of year			
26	**Funded Status**			
27	Unrecognized net actuarial loss	NOT APPLICABLE		
28	Unrecognized prior service cost			
29	Prepaid (accrued) benefit cost			
30	**Components of Net Periodic Benefit Costs**			
31	Service cost			
32	Interest cost	NOT APPLICABLE		
33	Expected return on plan assets			
34	Amortization of prior service cost			
35	Recognized net actuarial loss			
36	Net periodic benefit cost			
37	**Accumulated Post Retirement Benefit Obligation**			
38	Amount funded through VEBA			
39	Amount funded through 401(h)	NOT APPLICABLE		
40	Amount funded through other _______________			
41	TOTAL			
42	Amount that was tax deductible - VEBA			
43	Amount that was tax deductible - 401(h)			
44	Amount that was tax deductible - Other			
45	TOTAL			
46	**Montana Intrastate Costs:**			
47	Pension costs	NOT APPLICABLE		
48	Pension costs capitalized			
49	Accumulated pension asset (liability) at year end			
50	**Number of Montana Employees:**			
51	Covered by the plan			
52	Not covered by the plan	NOT APPLICABLE		
53	Active			
54	Retired			
55	Spouses/dependants covered by the plan			

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	The Commission has declared, by administrative rule, that some of Montana-Dakota's employees no longer have the right to maintain the privacy of their salary information (ARM 38.2.5031). Montana-Dakota has been advised by its legal counsel that the existence of that administrative rule effectively prohibits it from providing such information to the Commission on a voluntary basis, and that the Commission will need to institute proceedings to compel the disclosure of the requested salary information.						
6							
7							
8							
9							
10							

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

SCHEDULE 17

Year: 2011

COMPENSATION OF TOP 5 CORPORATE EMPLOYEES - SEC INFORMATION 1/

Line No.	Name/Title	Base Salary	Bonuses	Other 2/	Total Compensation	Total Compensation Last Year 2/	% Increase Total Compensation
1	Terry D. Hildestad President & CEO	$750,000	$954,750	$1,861,577	$3,566,327	$2,860,918	25%
2	Doran N. Schwartz Vice President and CFO	273,000	173,765	378,679	825,444	628,239	31%
3	John G. Harp President & CEO of MDU Construction Services Group, Inc.	450,000	438,750	923,121	1,811,871	1,544,075	17%
4	J. Kent Wells President & CEO of Fidelity Exploration & Production Company	367,671	1,923,991	1,014,505	3,306,167	N/A	N/A
5	William E. Schneider President & CEO of Knife River Corporation	447,400	436,215	837,670	1,721,285	1,126,735	53%

1/ See Schedule 17A for Total Compensation detail.

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

Compensation Committee Report

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

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

Summary Compensation Table for 2011

Name and Principal Position (a)	Year (b)	Salary ($) (c)	Bonus ($) (d)	Stock Awards ($) (e)(1)	Option Awards ($) (f)	Non-Equity Incentive Plan Compensation ($) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (h)(2)	All Other Compensation ($) (i)	Total ($) (j)
Terry D. Hildestad	2011	750,000	–	1,084,318	–	954,750	739,760	37,499 (3)	3,566,327
President and CEO	2010	750,000	–	830,137	–	762,750	480,532	37,499	2,860,918
	2009	750,000	–	1,117,861	–	1,500,000	825,319	9,824	4,203,004
Doran N. Schwartz	2011	273,000	–	197,341	–	173,765	147,789	33,549 (3)	825,444
Vice President and CFO	2010	252,454	–	143,881	–	127,053	71,302	33,549	628,239
	2009	–	–	–	–	–	–	–	–
John G. Harp	2011	450,000	–	390,345	–	438,750	481,331 (4)	51,445 (3)	1,811,871
President and CEO of	2010	450,000	–	298,845	–	438,750	307,935	48,545 (5)	1,544,075
MDU Construction	2009	450,000	–	402,417	–	392,500 (6)	761,670	23,272 (5)	2,029,859
Services Group, Inc.									
J. Kent Wells	2011	367,671	916,685 (7)	925,000 (8)	–	1,007,306 (9)	–	89,505 (3)	3,306,167
President and CEO of	2010	–	–	–	–	–	–	–	–
Fidelity Exploration &	2009	–	–	–	–	–	–	–	–
Production Company									
William E. Schneider	2011	447,400	–	388,086	–	436,215	412,085	37,499 (3)	1,721,285
President and CEO of	2010	447,400	–	297,122	–	37,805	306,909	37,499	1,126,735
Knife River Corporation	2009	447,400	–	400,093	–	581,620	726,646	9,324	2,165,083

(1) Amounts in this column represent the aggregate grant date fair value of the performance share awards calculated in accordance with Financial Accounting Standards Board generally accepted accounting principles for stock-based compensation in FASB Accounting Standards Codification Topic 718. This column was prepared assuming none of the awards will be forfeited. The amounts were calculated using a Monte Carlo simulation, as described in Note 13 of our audited financial statements in our Annual Report on Form 10-K for the year ended December 31, 2011.

(2) Amounts shown represent the change in the actuarial present value for years ended December 31, 2009, 2010, and 2011 for the named executive officers' accumulated benefits under the pension plan, excess SISP, and SISP and, for Mr. Harp, the additional retirement benefit, collectively referred to as the "accumulated pension change," plus above market earnings on deferred annual incentives, if any. The amounts shown are based on accumulated pension change and above market earnings as of December 31, 2009, 2010, and 2011, as follows:

	Accumulated Pension Change			Above Market Earnings		
Name	12/31/2009 ($)	12/31/2010 ($)	12/31/2011 ($)	12/31/2009 ($)	12/31/2010 ($)	12/31/2011 ($)
Terry D. Hildestad	806,554	462,186	728,587	18,765	18,346	11,173
Doran N. Schwartz	–	71,302	147,789	–	–	–
John G. Harp	743,334	294,023	459,963	–	–	–
Additional Retirement (4)	18,336	13,912	21,368	–	–	–
J. Kent Wells	–	–	–	–	–	–
William E. Schneider	696,572	277,507	393,768	30,074	29,402	18,317

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(3)

	401(k) ($)(a)	Life Insurance Premium ($)	Matching Charitable Contribution ($)	Office and Automobile Allowance ($)	Additional LTD Premium ($)	Relocation ($)(b)	Parking ($)	Payment In Lieu of Medical Coverage ($)	Spousal Travel ($)	Wellness Fitness ($)	Total ($)
Terry D. Hildestad	35,525	174	1,800	–	–	–	–	–	–	–	37,499
Doran N. Schwartz	33,075	174	300	–	–	–	–	–	–	–	33,549
John G. Harp	35,525	174	1,800	13,200	746	–	–	–	–	–	51,445
J. Kent Wells	19,600	116	–	–	–	66,031	2,400	700	508	150	89,505
William E. Schneider	35,525	174	1,800	–	–	–	–	–	–	–	37,499

(a) Represents company contributions to 401(k) plan, which include matching contributions and, except for Mr. Wells, contributions made in lieu of pension plan accruals after pension plans were frozen at December 31, 2009.

(b) Mr. Wells' 2011 relocation benefits were:

Temporary Living ($)	Actual Move and Related Expense ($)	Relocation Allowance ($)
18,000	2,198	45,833

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

	2009	2010	2011
Change in present value of additional years of service for pension plan	$13,077	$12,240	$19,407
Change in present value of additional years of service for excess SISP	5,259	1,672	1,961
Change in present value of additional years of service for SISP	–	–	–

Mr. Harp's additional retirement benefit is described in the narrative that follows the Pension Benefits for 2011 table. The additional retirement benefit provides Mr. Harp with additional retirement benefits equal to the additional benefit he would earn under the pension plan, excess SISP, and the SISP if he had three additional years of service. The pension and excess SISP were frozen as of December 31, 2009. The amounts in the table above reflect the change in present value of this additional benefit in 2009, 2010, and 2011. The additional retirement benefit was determined by calculating the actuarial present values of the accumulated benefits under the pension plan, excess SISP, and SISP, with and without the three additional years of service, using the same assumptions used to determine the amounts disclosed in the Pension Benefits for 2011 table. Because Mr. Harp would be fully vested in his SISP benefit if he retired at age 65, the assumed retirement age of these calculations, the additional years of service provided by the additional retirement agreement would not increase that benefit. If Mr. Harp retires before becoming 100% vested in his SISP benefit, his SISP benefit would be less than the amount shown in the Pension Benefits for 2011 table, but the payments he would receive under the additional retirement benefit arrangement would increase, as would the amounts reflected in the table above and in the Summary Compensation Table.

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

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

(7) Includes a cash recruitment payment of $550,000 and guaranteed target annual incentive payment of $366,685.

(8) Represents the aggregate grant date fair value of the portion of Mr. Wells' additional 2011 annual incentive award that was to be paid in shares of our common stock calculated in accordance with Financial Accounting Standards Board generally accepted accounting principles for stock-based compensation in FASB Accounting Standards Codification Topic 718.

(9) Includes $82,296, the value of Mr. Wells' annual incentive earned above the guaranteed target amount and the $925,010 cash portion of Mr. Wells' additional 2011 annual incentive.

Grants of Plan-Based Awards in 2011

Name (a)	Grant Date (b)	Board Approval Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards: Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Estimated Future Payouts Under Equity Incentive Plan Awards: Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	All Other Stock Awards: Number of Shares of Stock or Units (#) (i)	All Other Option Awards: Number of Securities Underlying Options (#) (j)	Exercise or Base Price of Option Awards ($/Sh) (k)	Grant Date Fair Value of Stock and Option Awards ($) (l)
Terry D.	2/17/11(1)	–	187,500	750,000	1,500,000	–	–	–	–	–	–	–
Hildestad	2/17/11(2)	–	–	–	–	5,424	54,243	108,486	–	–	–	1,084,318
Doran N.	2/17/11(1)	–	34,125	136,500	273,000	–	–	–	–	–	–	–
Schwartz	2/17/11(2)	–	–	–	–	987	9,872	19,744	–	–	–	197,341
John G.	2/17/11(1)	–	73,125	292,500	585,000	–	–	–	–	–	–	–
Harp	2/17/11(2)	–	–	–	–	1,953	19,527	39,054	–	–	–	390,345
J. Kent Wells	2/17/11(3)	–	–	366,685	733,370	–	–	–	–	–	–	–
	5/02/11(4)	2/17/11(4)	–	925,000	–	–	–	–	–	–	–	–
	5/02/11(4)	2/17/11(4)	–	–	–	–	$925,000(4)	–	–	–	–	925,000
William E.	2/17/11(1)	–	72,703	290,810	581,620	–	–	–	–	–	–	–
Schneider	2/17/11(2)	–	–	–	–	1,941	19,414	38,828	–	–	–	388,086

(1) Annual incentive for 2011 granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan, except for Mr. Schwartz whose award was granted pursuant to the MDU Resources Group, Inc. Executive Incentive Compensation Plan.

(2) Performance shares for the 2011-2013 performance period granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan.

(3) Annual incentive for 2011 granted pursuant to the WBI Holdings, Inc. Executive Incentive Compensation Plan. Mr. Wells was guaranteed a minimum payment of 100% of target.

(4) Additional 2011 annual incentive granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan, payable one-half in cash and one-half in our common stock. The award was approved on February 17, 2011, but the grant date for purposes of FASB Accounting Standards Codification Topic 718 was May 2, 2011, Mr. Wells' hire date. The $925,000 shown in column (g) represents the dollar value of the portion of Mr. Wells' additional 2011 annual incentive award that was paid in shares of our common stock determined by dividing $925,000 by the stock price on January 2, 2012, according to the terms of Mr. Wells' award.

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

Incentive Awards

Annual Incentive

On February 15, 2011, the compensation committee recommended the 2011 annual incentive award opportunities for our named executive officers and the board approved these opportunities at its meeting on February 17, 2011. These award opportunities are reflected in the Grants of Plan-Based Awards table at grant on February 17, 2011, in columns (c), (d), and (e) and in the Summary Compensation Table as earned with respect to 2011 in column (g). For Mr. Wells, the compensation committee guaranteed a minimum payment of 100% of target, prorated to reflect his May 2, 2011 hire date, which is reflected in the Grants of Plan-Based Awards table at grant on February 17, 2011, in column (d) and in the Summary Compensation Table in column (d). Mr. Wells could achieve a maximum of 200% of target, which is reflected at grant on February 17, 2011, in the Grants of Plan-Based Awards table in column (e), and the amount that he earned above target with respect to this award is reflected in the Summary Compensation Table in column (g).

Other than the arrangements negotiated for Mr. Wells for 2011, executive officers may receive a payment of annual cash incentive awards based upon achievement of annual performance measures with a threshold, target, and maximum level. A target incentive award is established based on a percent of the executive's base salary. Actual payment may range from 0% to 200% of the target based upon achievement of goals.

In order to be eligible to receive a payment of an annual incentive award under the Long-Term Performance-Based Incentive Plan, Messrs. Hildestad, Harp, and Schneider must have remained employed by the company through December 31, 2011, unless the compensation committee determines otherwise. The committee has full discretion to determine the extent to which goals have been achieved, the payment level, whether any final payment will be made, and whether to adjust awards downward based upon individual performance. Unless otherwise determined and established in writing by the compensation committee within 90 days of the beginning of the performance period, the performance goals may not be adjusted if the adjustment would increase the annual incentive award payment. The compensation committee may use negative discretion and adjust any annual incentive award payment downward, using

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any subjective or objective measures as it shall determine, including but not limited to the 20% limitation described in the following sentence. The 20% limitation means that no more than 20% of after-tax earnings that are in excess of planned earnings at the business unit level for operating company executives and at the MDU Resources Group level for corporate executives will be paid in annual incentives to executives. The application of this limitation or any other reduction, and the methodology used in determining any such reduction, is in the sole discretion of the compensation committee.

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

Messrs. Harp's and Schneider's performance goals for 2011 are budgeted earnings per share achieved and budgeted return on invested capital achieved, each weighted 50%. The goals are measured at the business unit level, as allocated, for Mr. Harp and Mr. Schneider.

For Messrs. Harp and Schneider, achievement of budgeted earnings per share and return on invested capital would result in payment of 100% of the target amount. Their 2011 award opportunities ranged from no payment if the allocated earnings per share and return on invested capital were below the 85% level to a 200% payout for achievement of 115% of budgeted earnings per share and a return on invested capital equal to or greater than the business unit's weighted average cost of capital would result in payment of 200% of the target amount.

For Mr. Wells, the committee guaranteed a minimum payment of 100% of target, prorated to reflect his May 2, 2011 hire date. The 2011 incentive award opportunity was based on the financial goals for both Fidelity Exploration & Production Company and WBI Holdings, Inc., weighted 75% for the results of Fidelity Exploration & Production Company and 25% for the results of WBI Holdings, Inc. The incentive award could be reduced by up to 10% if Fidelity Exploration & Production Company did not meet its production goal and by up to 5% if WBI Holdings, Inc. did not satisfy its safety goals. Mr. Wells could achieve a maximum of 200% of the annual incentive target if:

- the 2011 allocated earnings per share for Fidelity Exploration & Production Company and the 2011 allocated earnings per share for WBI Holdings, Inc., were at or above 115% of the performance target
- the 2011 return on invested capital for Fidelity Exploration & Production Company and the 2011 return on invested capital for WBI Holdings, Inc. were both at least equal to their respective weighted average costs of capital
- Fidelity Exploration & Production Company achieved production of at least 69.3 billion cubic feet equivalent (Bcfe) and
- the five safety goals for WBI Holdings, Inc. were met.

Annual incentive award payments for Messrs. Hildestad and Schwartz were determined based on the annual incentive award payments made to the president and chief executive officers of the four business units – MDU Construction Services Group, Inc., Knife River Corporation, WBI Holdings, Inc., and Combined Utility Group – and were calculated as follows: each business unit president and chief executive officer's annual incentive award payment, expressed as a percentage of his annual target award, was multiplied by that business unit's percentage share of average invested capital for 2011. These four products were added together, and the sum was multiplied by Messrs. Hildestad's and Schwartz's 2011 target incentive. Messrs. Hildestad's and Schwartz's 2011 annual incentives were paid at 127.3% of target based on the following:

President and Chief Executive Officer of:	Column A 2011 Payment as a Percentage of Annual Incentive Target	Column B Percentage of Average Invested Capital	Column A x Column B
MDU Construction Services Group, Inc.	150.0%	6.1%	9.2%
Knife River Corporation	150.0%	24.4%	36.6%
WBI Holdings, Inc.	97.8%	34.6%	33.8%
Combined Utility Group	136.7%	34.9%	47.7%
Total			127.3%

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The award opportunities available to Messrs. Harp and Schneider were:

2011 return on invested capital results as a % of 2011 target	Corresponding payment of annual incentive target based on return on invested capital
Less than 85%	0%
85%	25%
90%	50%
95%	75%
100%	100%
103%	100%
106%	100%
109%	100%
112%	100%
Up to weighted average cost of capital	100%
Weighted average cost of capital or higher	200%

2011 earnings per share results as a % of 2011 target	Corresponding payment of annual incentive target based on earnings per share
Less than 85%	0%
85%	25%
90%	50%
95%	75%
100%	100%
103%	120%
106%	140%
109%	160%
112%	180%
115%	200%

The award opportunities available to Mr. Wells with respect to the financial results component of his award were:

Fidelity Exploration & Production Company – weighted 75%

2011 return on invested capital results as a % of 2011 target	Corresponding payment of annual incentive target based on return on invested capital
Less than 85%	0%
85%	25%
90%	50%
95%	75%
100%	100%
103%	100%
106%	100%
109%	100%
112%	100%
Up to weighted average cost of capital	100%
Weighted average cost of capital or higher	200%

2011 earnings per share results as a % of 2011 target	Corresponding payment of annual incentive target based on earnings per share
Less than 85%	0%
85%	25%
90%	50%
95%	75%
100%	100%
103%	120%
106%	140%
109%	160%
112%	180%
115%	200%

WBI Holdings, Inc. – weighted 25%

2011 return on invested capital results as a % of 2011 target	Corresponding payment of annual incentive target based on return on invested capital
Less than 85%	0%
85%	25%
90%	50%
95%	75%
100%	100%
103%	100%
106%	100%
109%	100%
112%	100%
Up to weighted average cost of capital	100%
Weighted average cost of capital or higher	200%

2011 earnings per share results as a % of 2011 target	Corresponding payment of annual incentive target based on earnings per share
Less than 85%	0%
85%	25%
90%	50%
95%	75%
100%	100%
103%	120%
106%	140%
109%	160%
112%	180%
115%	200%

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

J. Kent Wells' Additional 2011 Annual Incentive

On February 15, 2011, the compensation committee recommended the grant of a second 2011 annual incentive award opportunity to Mr. Wells pursuant to the Long-Term Performance-Based Incentive Plan, based on Fidelity Exploration & Production Company's cash flow from operations. The board approved this opportunity at its meeting on February 17, 2011. Specifically, we granted Mr. Wells an all-or-nothing award opportunity of $1.85 million, payable one-half in cash and one-half in our common stock, if Fidelity Exploration & Production Company's 2011 cash flow from operations exceeded $132.0 million and he did not resign from the company prior to January 2, 2012. If Fidelity Exploration & Production Company's 2011 cash flow from operations exceeded $132.0 million and Mr. Wells' employment was terminated prior to January 2, 2012, due to a change in control of the company, Mr. Wells would have been entitled to full payment of this incentive award.

Fidelity Exploration & Production Company's actual 2011 cash flow from operations exceeded $132.0 million, resulting in a payment of $1.85 million to Mr. Wells. The cash portion paid to Mr. Wells is reported in the Summary Compensation Table in column (g), and the grant date fair value of the stock portion of the award is reported in the Summary Compensation Table in column (e).

J. Kent Wells' Recruitment Bonus

We paid a cash recruitment bonus of $550,000 to induce Mr. Wells to join the company, which is reflected in the Summary Compensation Table in column (d).

Long-Term Incentive

On February 15, 2011, the compensation committee recommended long-term incentive grants to the named executive officers in the form of performance shares, and the board approved these grants at its meeting on February 17, 2011. These grants are reflected in columns (f), (g), (h), and (i) of the Grants of Plan-Based Awards table and in column (e) of the Summary Compensation Table.

If the company's 2011-2013 total shareholder return is positive, from 0% to 200% of the target grant will be paid out in February 2014, depending on our 2011-2013 total stockholder return compared to the total three-year stockholder returns of companies in our performance graph peer group. The payout percentage is determined as follows:

The Company's Percentile Rank	Payout Percentage of February 17, 2011 Grant
90th or higher	200%
70th	150%
50th	100%
40th	10%
Less than 40th	0%

Payouts for percentile ranks falling between the intervals will be interpolated. We also will pay dividend equivalents in cash on the number of shares actually earned for the performance period. The dividend equivalents will be paid in 2014 at the same time as the performance awards are paid.

If the company's 2011-2013 total shareholder return is negative, the number of shares otherwise earned, if any, for the performance period will be reduced in accordance with the following table:

TSR	Reduction in Award
0% through -5%	50%
-5.01% through -10%	60%
-10.01% through -15%	70%
-15.01% through -20%	80%
-20.01% through -25%	90%
-25.01% or below	100%

Salary and Bonus in Proportion to Total Compensation

The following table shows the proportion of salary and bonus to total compensation.

Name	Salary ($)	Bonus ($)	Total Compensation ($)	Salary and Bonus as a % of Total Compensation
Terry D. Hildestad	750,000	–	3,566,327	21.0
Doran N. Schwartz	273,000	–	825,444	33.1
John G. Harp	450,000	–	1,811,871	24.8
J. Kent Wells	367,671	916,685	3,306,167	38.8
William E. Schneider	447,400	–	1,721,285	26.0

Outstanding Equity Awards at Fiscal Year-End 2011

	Option Awards					Stock Awards			
Name (a)	Number of Securities Underlying Unexercised Options Exercisable (#) (b)	Number of Securities Underlying Unexercised Options Unexercisable (#) (c)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#) (d)	Option Exercise Price ($) (e)	Option Expiration Date (f)	Number of Shares or Units of Stock That Have Not Vested (#) (g)	Market Value of Shares or Units of Stock That Have Not Vested ($) (h)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (i)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (j)(1)
Terry D. Hildestad	–	–	–	–	–	–	–	118,739(2)	2,548,139
Doran N. Schwartz	–	–	–	–	–	–	–	21,062(2)	451,991
John G. Harp	–	–	–	–	–	–	–	42,746(2)	917,329
J. Kent Wells	–	–	–	–	–	–	–	43,103(3)	925,000
William E. Schneider	–	–	–	–	–	–	–	42,498(2)	912,007

(1) Value based on the number of performance shares reflected in column (i) multiplied by $21.46, the year-end closing price for 2011.

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

Named Executive Officer	Award	Shares	End of Performance Period
Terry D. Hildestad	2009	5,482	12/31/11
	2010	4,771	12/31/12
	2011	108,486	12/31/13
Doran N. Schwartz	2009	491	12/31/11
	2010	827	12/31/12
	2011	19,744	12/31/13
John G. Harp	2009	1,974	12/31/11
	2010	1,718	12/31/12
	2011	39,054	12/31/13
William E. Schneider	2009	1,962	12/31/11
	2010	1,708	12/31/12
	2011	38,828	12/31/13

Shares for the 2009 award are shown at the threshold level (10%) based on results for the 2009-2011 performance cycle below threshold. Shares for the 2010 award are shown at the threshold level (10%) based on results for the first two years of the 2010-2012 performance cycle below threshold. Shares for the 2011 award are shown at the maximum level (200%) based on results for the first year of the 2011-2013 performance cycle above target.

(3) The number of shares for the additional 2011 annual incentive equity award of $925,000 was determined by using the year-end closing price for 2011 of $21.46. These shares vested February 16, 2012.

Pension Benefits for 2011

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)	Present Value of Accumulated Benefit ($) (d)	Payments During Last Fiscal Year ($) (e)
Terry D. Hildestad	MDU Pension Plan	35	1,619,835	–
	SISP I(1)(3)	10	1,951,968	–
	SISP II(2)(3)	10	3,222,988	–
	SISP Excess(4)	35	552,948	–
Doran N. Schwartz	MDU Pension Plan	4	78,419	–
	SISP II(2)(3)	4	403,676	–
John G. Harp	MDU Pension Plan	5	242,675	–
	SISP II(2)(3)	6	2,461,293	–
	SISP Excess(4)	5	40,291	–
	Harp Additional Retirement Benefit	3	155,416	–
J. Kent Wells(5)	–	–	–	–
William E. Schneider	KR Pension Plan	16	786,231	–
	SISP I(1)(3)	10	1,372,770	–
	SISP II(2)(3)	10	1,621,769	–
	SISP Excess(4)	16	46,259	–

(1) Grandfathered under Section 409A.

(2) Not grandfathered under Section 409A.

(3) Years of credited service only affects vesting under SISP I and SISP II. The number of years of credited service in the table reflects the years of vesting service completed in SISP I and SISP II as of December 31, 2011, rather than total years of service with the company. Ten years of vesting service is required to obtain the full benefit under these plans. The present value of accumulated benefits was calculated by assuming the named executive officer would have ten years of vesting service on the assumed benefit commencement date; therefore, no reduction was made to reflect actual vesting levels.

(4) The number of years of credited service under the SISP excess reflects the years of credited benefit service in the appropriate pension plan as of December 31, 2009, when the pension plans were frozen, rather than the years of participation in the SISP excess. We reflect years of credited benefit service in the appropriate pension plan because the SISP excess provides a benefit that is based on benefits that would have been payable under the pension plans absent Internal Revenue Code limitations.

(5) Mr. Wells is not eligible to participate in our pension plan and does not participate in the SISP.

The amounts shown for the pension plan and SISP excess represent the actuarial present values of the executives' accumulated benefits accrued as of December 31, 2011, calculated using a 4.00%, 4.11%, and 4.07% discount rate for the SISP excess, MDU pension plan, and KR pension plan, respectively, the 2012 IRS Static Mortality Table for post-retirement mortality, and no recognition of future salary increases or pre-retirement mortality. The assumed retirement ages for these benefits was age 60 for Messrs. Schwartz and Harp. This is the earliest age at which the executives could begin receiving unreduced benefits. Retirement on December 31, 2011, was assumed for Messrs. Hildestad and Schneider, who were age 62 and 63, respectively, on that date. The amounts shown for the SISP I and SISP II were determined using a 4.00% discount rate and assume benefits commenced at age 65. The assumptions used to calculate Mr. Harp's additional retirement benefit are described below.

Pension Plans

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

Each of the pension plans was amended to cease benefit accruals as of December 31, 2009, meaning the normal retirement benefit will not change. The years of credited service in the table reflect the named executive officers' years of credited service as of December 31, 2009.

To receive unreduced retirement benefits under the MDU pension plan, participants must either remain employed until age 60 or elect to defer commencement of benefits until age 60. Under the KR pension plan, participants must remain employed until age 62 or elect to defer commencement of benefits until age 62 to receive unreduced benefits. Messrs. Hildestad and Schneider were eligible for unreduced retirement benefits under the MDU pension plan and KR pension plan, respectively, on December 31, 2011. Participants whose employment terminates between the ages of 55 and 60, with 5 years of service under the MDU pension plan are eligible for early retirement benefits. Early retirement benefits are determined by reducing the normal retirement benefit by 0.25% per month for each month before age 60 in the MDU pension plan. If a participant's employment terminates before age 55, the same reduction applies for each month the termination occurs before age 62, with the reduction capped at 21%. Mr. Harp is currently eligible for early retirement benefits.

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

The Internal Revenue Code limits the amounts that may be paid under the pension plans and the amount of compensation that may be recognized when determining benefits. In 2009 when the pension plans were frozen, the maximum annual benefit payable under the pension plans was $195,000 and the maximum amount of compensation that could be recognized when determining benefits was $245,000.

Supplemental Income Security Plan

We also offer key managers and executives, including our named executive officers, except Mr. Wells, benefits under our nonqualified retirement plan, which we refer to as the Supplemental Income Security Plan or SISP. Benefits under the SISP consist of:

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

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

Regular SISP Benefits and Death Benefits

Regular SISP benefits and death benefits are determined by reference to one of two schedules attached to the SISP – the original schedule or the amended schedule. Our compensation committee, after receiving recommendations from our chief executive officer, determines the level at which participants are placed in the schedules. A participant's placement is generally, but not always, determined by reference to the participant's annual base salary. Benefit levels in the amended schedule, which became effective on January 1, 2010, are 20% lower than the benefit levels in the original schedule. The amended schedule applies to new participants and participants who receive a benefit level increase on or after January 1, 2010. None of the named executive officers have received a benefit level increase since the amended schedule became effective.

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

The regular SISP benefits reflected in the table above are based on the assumption that the participant elects to receive only the regular SISP benefit. The present values of the SISP death benefits that would be provided if the named executive officers had died on December 31, 2011, prior to the commencement of regular SISP benefits, are reflected in the table that appears in the section entitled "Potential Payments upon Termination or Change of Control."

Regular SISP benefits that were vested as of December 31, 2004, and were thereby grandfathered under Section 409A of the Internal Revenue Code remain subject to SISP provisions then in effect, which we refer to as SISP I benefits. Regular SISP benefits that are subject to Section 409A of the Internal Revenue Code, which we refer to as SISP II benefits, are governed by amended provisions intended to comply with Section 409A. Participants generally have more discretion with respect to the distributions of their SISP I benefits.

The time and manner in which the regular SISP benefits are paid depend on a variety of factors, including the time and form of benefit elected by the participant and whether the benefits are SISP I or SISP II benefits. Unless the participant elects otherwise, the SISP I benefits are paid over 180 months, with benefits commencing when the participant attains age 65 or, if later, when the participant retires. The SISP II benefits commence when the participant attains age 65 or, if later, when the participant retires, subject to a six-month delay if the participant is subject to the provisions of Section 409A of the Internal Revenue Code that require delayed commencement of these types of retirement benefits. The SISP II benefits are paid over 180 months or, if commencement of payments is delayed for six months, 173 months. If the commencement of benefits is delayed for six months, the first payment includes the payments that would have been paid during the six-month period plus interest equal to one-half of the annual prime interest rate on the participant's last date of employment. If the participant dies after the regular SISP benefits have begun but before receipt of all of the regular SISP benefits, the remaining payments are made to the participant's designated beneficiary.

Rather than receiving their regular SISP I benefits in equal monthly installments over 15 years commencing at age 65, participants can elect a different form and time of commencement of their SISP I benefits. Participants can elect to defer commencement of the regular SISP I benefits. If this is elected, the participant retains the right to receive a monthly SISP death benefit if death occurs prior to the commencement of the regular SISP I benefit.

Participants also can elect to receive their SISP I benefits in one of three actuarially equivalent forms – a life annuity, 100% joint and survivor annuity, or a joint and two-thirds joint and survivor annuity, provided that the cost of providing these actuarial equivalent forms of benefits does not exceed the cost of providing the normal form of benefit. Neither the election to receive an actuarial equivalent benefit nor the administrator's right to pay the regular SISP benefit in the form of an actuarially equivalent lump sum are available with respect to SISP II benefits.

To promote retention, the regular SISP benefits are subject to the following 10-year vesting schedule:

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

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

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

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

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

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

SISP Excess Benefits

SISP excess benefits are equal to the difference between (1) the monthly retirement benefits that would have been payable to the participant under the pension plans absent the limitations under the Internal Revenue Code and (2) the actual benefits payable to the participant under the pension plans. Participants are only eligible for the SISP excess benefits if (1) the participant is fully vested under the pension plan, (2) the participant's employment terminates prior to age 65, and (3) benefits under the pension plan are reduced due to limitations under the Internal Revenue Code on plan compensation. Effective January 1, 2005, participants who were not then vested in the SISP excess benefits were also required to remain actively employed by the company until age 60. In 2009, the plan was amended to limit eligibility for the SISP excess benefit to current SISP participants (1) who were already vested in the SISP excess benefit or (2) who would become vested in the SISP excess benefits if they remain employed with the company until age 60. The plan was further amended to freeze the SISP excess benefits to a maximum of the benefit level payable based on the participant's years of service and compensation level as of December 31, 2009. Messrs. Hildestad and Schneider would be entitled to the SISP excess benefit if they were to terminate employment prior to age 65. Mr. Harp must remain employed until age 60 to become entitled to his SISP excess benefit. Messrs. Schwartz and Wells are not eligible for this benefit.

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

Mr. Harp's Additional Retirement Benefit

To encourage Mr. Harp to remain with the company, on November 16, 2006, upon recommendation of our chief executive officer and the compensation committee, our board of directors approved an additional retirement benefit for Mr. Harp. The benefit provides for Mr. Harp to receive payments that represent the equivalent of an additional three years of service under the pension plan, SISP excess, and SISP II. The additional three years of service recognize Mr. Harp's previous employment with a subsidiary of the company. To calculate payments Mr. Harp could receive due to his additional retirement benefit, we applied the additional years of service to each of the retirement arrangements and assumed he remained employed until age 60, for purposes of calculating the additional benefit under the pension plan and SISP excess, and age 65, for purposes of calculating the additional benefit under the SISP II. Since the pension plan and SISP excess were frozen as of December 31, 2009, no additional accruals will be recognized. Because we calculate the amounts shown in the table based on an assumption that the named executive officers are 100% vested in their SISP benefits, the additional years of service provided by the agreement would not increase his SISP II benefit reflected in the table. Consequently, the additional retirement benefit amount shown in the table does not include any additional benefit attributable to the SISP II. If Mr. Harp were to retire before achieving 10 years of service and becoming fully vested in his SISP II benefit, the additional years of service provided by the additional retirement benefit would increase his vesting percentage under the SISP II and, therefore, would increase his benefits under the SISP II. For a description of the payments that could be provided under the additional retirement benefit if Mr. Harp's employment were to be terminated on December 31, 2011, refer to the table and related notes in "Potential Payment upon Termination or Change of Control" below.

Nonqualified Deferred Compensation for 2011

Name (a)	Executive Contributions in Last FY ($) (b)	Registrant Contributions in Last FY ($) (c)	Earnings in Aggregate Last FY ($) (d)	Aggregate Withdrawals/ Distributions ($) (e)	Aggregate Balance at Last FYE ($) (f)
Terry D. Hildestad	–	–	52,968	–	948,527
Doran N. Schwartz	–	–	–	–	–
John G. Harp	–	–	–	–	–
J. Kent Wells	–	–	–	–	–
William E. Schneider	37,805	–	86,836	–	1,559,891(1)

(1) Includes $392,000 which was reported in the Summary Compensation Table for 2006 in column (g) and $37,805 which is reported for 2010 in column (g) of the Summary Compensation Table in this proxy statement.

Participants in the executive incentive compensation plans may elect to defer up to 100% of their annual incentive awards. Deferred amounts accrue interest at a rate determined annually by the compensation committee. The interest rate in effect for 2011 was 5.76% or the "Moody's Rate," which is the average of (i) the number that results from adding the daily Moody's U.S. Long-Term Corporate Bond Yield Average for "A" rated companies as of the last day of each month for the 12-month period ending October 31 and dividing by 12 and (ii) the number that results from adding the daily Moody's U.S. Long-Term Corporate Bond Yield Average for "BBB" rated companies as of the last day of each month for the 12-month period ending October 31 and dividing by 12. The deferred amount will be paid in accordance with the participant's election, following termination of employment or beginning in the fifth year following the year the award was granted. The amounts will be paid in accordance with the participant's election in a lump sum or in monthly installments not to exceed 120 months. In the event of a change of control, all amounts become immediately payable.

A change of control is defined as:

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

Potential Payments upon Termination or Change of Control

The following tables show the payments and benefits our named executive officers would receive in connection with a variety of employment termination scenarios and upon a change of control. For the named executive officers, the information assumes the terminations and the change of control occurred on December 31, 2011. All of the payments and benefits described below would be provided by the company or its subsidiaries.

The tables exclude compensation and benefits provided under plans or arrangements that do not discriminate in favor of the named executive officers and that are generally available to all salaried employees, such as benefits under our qualified defined benefit pension plan, accrued vacation pay, continuation of health care benefits, and life insurance benefits. The tables also do not include the named executive officers' benefits under our nonqualified deferred compensation plans, which are reported in the Nonqualified Deferred Compensation for 2011 table. See the Pension Benefits for 2011 table and the Nonqualified Deferred Compensation for 2011 table, and accompanying narratives, for a description of the named executive officers' accumulated benefits under our qualified defined benefit pension plans and our nonqualified deferred compensation plans.

We provide disability benefits to some of our salaried employees equal to 60% of their base salary, subject to a cap on the amount of base salary taken into account when calculating benefits. For officers, the limit on base salary is $200,000. For other salaried employees, the limit is $100,000. For all salaried employees, disability payments continue until age 65 if disability occurs at or before age 60 and for 5 years if disability occurs between the ages of 60 and 65. Disability benefits are reduced for amounts paid as retirement benefits. The amounts in the tables reflect the present value of the disability benefits attributable to the additional $100,000 of base salary recognized for executives under our disability program, subject to the 60% limitation, after reduction for amounts that would be paid as retirement benefits. As the tables reflect, with the exception of Messrs. Schwartz and Harp, the reduction for amounts paid as retirement benefits would eliminate disability benefits assuming a termination of employment on December 31, 2011. The table for Mr. Wells does not reflect a disability benefit as he had not exhausted the eligibility waiting period of one year as of December 31, 2011.

According to the terms of Mr. Wells' letter agreement, we agreed to pay Mr. Wells a guaranteed minimum payment of 100% of target of his annual incentive award under the WBI Holdings, Inc. Executive Incentive Compensation Plan, prorated to reflect his May 2, 2011 hire date. In addition, if Mr. Wells' employment had ended before January 2, 2012, due to a change of control, as defined in Section 409A of the Internal Revenue Code of 1986, as amended, we agreed to pay Mr. Wells' additional annual incentive of $1.85 million in full if the performance goal was met.

Upon a change of control, share-based awards granted under our Long-Term Performance-Based Incentive Plan vest and non-share-based awards are paid in cash. All performance share awards for Messrs. Hildestad, Schwartz, Harp, and Schneider and the annual incentives for Messrs. Hildestad, Harp, Wells, and Schneider, which were awarded under the Long-Term Performance-Based Incentive Plan, would vest at their target levels. For this purpose, the term "change of control" is defined as:

- the acquisition by an individual, entity, or group of 20% or more of our outstanding common stock
- a change in a majority of our board of directors since April 22, 1997, without the approval of a majority of the board members as of April 22, 1997, or whose election was approved by such board members
- consummation of a merger or similar transaction or sale of all or substantially all of our assets, unless our stockholders immediately prior to the transaction beneficially own more than 60% of the outstanding common stock and voting power of the resulting corporation in substantially the same proportions as before the merger, no person owns 20% or more of the resulting corporation's outstanding common stock or voting power except for any such ownership that existed before the merger and at least a majority of the board of the resulting corporation is comprised of our directors or
- stockholder approval of our liquidation or dissolution.

Performance share awards will be forfeited if the participant's employment terminates for any reason before the participant has reached age 55 and completed 10 years of service. Performance shares and related dividend equivalents for those participants whose employment is terminated other than for cause after the participant has reached age 55 and completed 10 years of service will be prorated as follows:

- if the termination of employment occurs during the first year of the performance period, the shares are forfeited
- if the termination of employment occurs during the second year of the performance period, the executive receives a prorated portion of any performance shares earned based on the number of months employed during the performance period and
- if the termination of employment occurs during the third year of the performance period, the executive receives the full amount of any performance shares earned.

Of the named executive officers with performance share awards, only Mr. Schwartz had not satisfied this requirement as of December 31, 2011. Accordingly, if a December 31, 2011 termination other than for cause without a change of control is assumed, the named executive officers' 2011-2013 performance share awards would be forfeited, any amounts earned under the 2010-2012 performance share awards for Messrs. Hildestad, Harp, and Schneider would be reduced by one-third and such award for Mr. Schwartz would be forfeited, and any amounts earned under the 2009-2011 performance share awards for Messrs. Hildestad, Harp, and Schneider would not be reduced and the award for Mr. Schwartz would be forfeited. The number of performance shares earned following a termination depends on actual performance through the full performance period. As actual performance for the 2009-2011 performance share awards has been determined, the amounts for these awards in the event of a termination without a change of control were based on actual performance, which resulted in vesting of 0% of the target award. For the 2010-2012 performance share awards, because we do not know what actual performance through the entire performance period will be, we have assumed target performance will be achieved and, therefore, show two-thirds of the target award. No amounts are shown for the 2011-2013 performance share awards because such awards would be forfeited. Although vesting would only occur after completion of the performance period, the amounts shown in the tables were not reduced to reflect the present value of the performance shares that could vest. Dividend equivalents attributable to earned performance shares would also be paid. Dividend equivalents accrued through December 31, 2011, are included in the amounts shown.

The value of the vesting of performance shares shown in the tables was determined by multiplying the number of performance shares that would vest due to termination or a change of control by the closing price of our stock on December 31, 2011.

Except for Messrs. Hildestad and Wells, we also have change of control employment agreements with our named executive officers and other executives, which provide certain protections to the executives in the event there is a change of control of the company. Mr. Hildestad requested that his change of control employment agreement be terminated in June 2010. The compensation committee notified other executives with change of control employment agreements that their agreements would not be extended beyond their current expiration dates.

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

- the acquisition by an individual, entity, or group of 20% or more of our outstanding common stock
- a change in a majority of our board of directors since the date of the agreement without the approval of a majority of the board members as of the date of the agreement or whose election was approved by such board members
- consummation of a merger of similar transaction or sale of all or substantially all of our assets, unless our stockholders immediately prior to the transaction beneficially own more than 60% of the outstanding common stock and voting power of the resulting corporation in substantially the same proportions as before the merger, no person owns 20% or more of the resulting corporation's outstanding common stock or voting power except for any such ownership that existed before the merger and at least a majority of the board of the resulting corporation is comprised of our directors or
- stockholder approval of our liquidation or dissolution.

If a change of control occurs, the agreements provide for a three-year employment period from the date of the change of control, during which the named executive officer is entitled to receive:

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

Assuming a change of control occurred on December 31, 2011, the guaranteed minimum level of base salary provided over the three-year employment period would not result in an increase in any of the named executive officers' base salaries. The minimum annual incentive opportunities Messrs. Schwartz, Harp, and Schneider would be eligible to earn over the three-year employment period would be $543,780, $1,316,250, and $1,744,860, respectively. The agreements also provide that severance payments and benefits will be provided:

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

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

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

In such event, the named executive officer would receive:

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

This description of severance payments and benefits reflects the terms of the agreements as in effect on December 31, 2011.

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

Terry D. Hildestad

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination ($)	Not for Cause Termination ($)	For Cause Termination ($)	Death ($)	Disability ($)	Change of Control (With Termination) ($)	Change of Control (Without Termination) ($)
Compensation:							
Short-term Incentive(1)						750,000	750,000
2009-2011 Performance Shares						1,281,374	1,281,374
2010-2012 Performance Shares	723,587	723,587		723,587	723,587	1,085,380	1,085,380
2011-2013 Performance Shares						1,199,584	1,199,584
Benefits and Perquisites:							
Regular SISP(2)	5,242,870	5,242,870			5,242,870	5,242,870	
Excess SISP(3)	552,948	552,948			552,948	552,948	
SISP Death Benefits(4)				11,586,607			
Total	**6,519,405**	**6,519,405**		**12,310,194**	**6,519,405**	**10,112,156**	**4,316,338**

(1) Represents the target 2011 annual incentive, which would be deemed earned upon change of control under the Long-Term Performance-Based Incentive Plan.

(2) Represents the present value of Mr. Hildestad's vested regular SISP benefit as of December 31, 2011, which was $42,710 per month for 15 years, commencing at age 65. Present value was determined using a 4.00% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2011 table.

(3) Represents the present value of all excess SISP benefits Mr. Hildestad would be entitled to upon termination of employment under the SISP. Present value was determined using a 4.00% discount rate. The terms of the excess SISP benefit are described following the Pension Benefits for 2011 table.

(4) Represents the present value of 180 monthly payments of $85,420 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 4.00% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2011 table.

Doran N. Schwartz

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination ($)	Not for Cause Termination ($)	For Cause Termination ($)	Death ($)	Disability ($)	Not for Cause or Good Reason Termination Following Change of Control ($)	Change of Control (Without Termination) ($)
Compensation:							
Base Salary						819,000	
Short-term Incentive(1)						725,040	
2009-2011 Performance Shares						114,689	114,689
2010-2012 Performance Shares						188,120	188,120
2011-2013 Performance Shares						218,319	218,319
Benefits and Perquisites:							
Regular SISP	160,738(2)	160,738(2)			241,107(3)	281,292(4)	
SISP Death Benefits(5)				1,980,385			
Disability Benefits(6)					842,408		
Outplacement Services						50,000	
280G Tax(7)						417,848	
Total	**160,738**	**160,738**		**1,980,385**	**1,083,515**	**2,814,308**	**521,128**

(1) Includes the prorated annual incentive for the year of termination, which is the full annual incentive since we assume termination occurred on December 31, 2011, and the additional severance payment of three times the annual incentive. For each of these, we used the higher of (1) the annual incentive earned in 2011 or (2) the highest annual incentive paid in 2009, 2010, and 2011.

(2) Represents the present value of Mr. Schwartz's vested regular SISP benefit as of December 31, 2011, which was $2,920 per month for 15 years, commencing at age 65. Present value was determined using a 4.00% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2011 table.

(3) Represents the present value of Mr. Schwartz's vested SISP benefit described in footnote 2, adjusted to reflect the increase in the present value of his regular SISP benefit that would result from an additional two years of vesting under the SISP. Present value was determined using a 4.00% discount rate.

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

(5) Represents the present value of 180 monthly payments of $14,600 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 4.00% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2011 table.

(6) Represents the present value of the disability benefit after reduction for amounts that would be paid as retirement benefits. Present value was determined using a 4.11% discount rate.

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

John G. Harp

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination ($)	Not for Cause Termination ($)	For Cause Termination ($)	Death ($)	Disability ($)	Not for Cause or Good Reason Termination Following Change of Control ($)	Change of Control (Without Termination) ($)
Compensation:							
Base Salary						1,350,000	
Short-term Incentive						1,755,000(1)	292,500(2)
2009-2011 Performance Shares						461,280	461,280
2010-2012 Performance Shares	260,488	260,488		260,488	260,488	390,731	390,731
2011-2013 Performance Shares						431,840	431,840
Benefits and Perquisites:							
Incremental Pension(3)	136,432	136,432			136,432	136,432	
Regular SISP	2,215,163(4)	2,215,163(4)			2,461,292(5)	2,461,292(6)	
SISP Death Benefits(7)				6,198,875			
Disability Benefits(8)					178,455		
Outplacement Services						50,000	
280G Tax(9)						718,845	
Total	**2,612,083**	**2,612,083**		**6,459,363**	**3,036,667**	**7,755,420**	**1,576,351**

(1) Includes the prorated annual incentive for the year of termination, which is the full annual incentive since we assume termination occurred on December 31, 2011, and the additional severance payment of three times the annual incentive. For each of these, we used the higher of (1) the annual incentive earned in 2011 or (2) the highest annual incentive paid in 2009, 2010, and 2011.

(2) Represents the target 2011 annual incentive, which would be deemed earned upon change of control under the Long-Term Performance-Based Incentive Plan.

(3) Represents the equivalent of three additional years of service that would be provided under the Harp additional retirement benefit described following the Pension Benefits for 2011 table. Present value was determined using a 4.11% discount rate.

(4) Represents the present value of Mr. Harp's vested regular SISP benefit as of December 31, 2011, which was $20,565 per month for 15 years, commencing at age 65. Present value was determined using a 4.00% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2011 table. Also includes the additional benefit attributable to three additional years of service that would be provided under the retirement benefit agreement described following the Pension Benefits for 2011 table.

(5) Represents the present value of Mr. Harp's vested SISP benefit described in footnote 4, adjusted to reflect the increase in the present value of his regular SISP benefit that would result from an additional two years of vesting under the SISP. Present value was determined using a 4.00% discount rate.

(6) Represents the present value of Mr. Harp's vested SISP benefit described in footnote 4, adjusted to reflect the increase in the present value of his regular SISP benefit that would result if he continued employment for an additional three years. Present value was determined using a 4.00% discount rate.

(7) Represents the present value of 180 monthly payments of $45,700 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 4.00% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2011 table.

(8) Represents the present value of the disability benefit after reduction for amounts that would be paid as retirement benefits. Present value was determined using a 4.11% discount rate.

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

J. Kent Wells

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination ($)	Not for Cause Termination ($)	For Cause Termination ($)	Death ($)	Disability ($)	Change of Control (With Termination) ($)	Change of Control (Without Termination) ($)
Compensation:							
Short-term Incentive(1)	366,685	366,685	366,685	366,685	366,685	366,685	366,685
Additional 2011 Annual Incentive		1,850,000(2)	1,850,000(2)	1,850,000(2)	1,850,000(2)	1,850,000(3)	1,850,000(4)
Total	**366,685**	**2,216,685**	**2,216,685**	**2,216,685**	**2,216,685**	**2,216,685**	**2,216,685**

(1) Represents the guaranteed minimum annual incentive payment of 100% of target for 2011, prorated to reflect Mr. Wells' May 2, 2011 hire date.

(2) Mr. Wells was eligible to receive payment of his 2011 additional annual incentive if he did not resign from Fidelity Exploration & Production Company before January 2, 2012, and the goal was met.

(3) Mr. Wells would receive payment of his 2011 additional annual incentive if Fidelity Exploration & Production Company's cash flow from operations for 2011 exceeded $132.0 million and his employment ended for any reason before January 2, 2012, due to a change in control of MDU Resources Group, Inc.

(4) Represents the 2011 additional annual incentive, which would be deemed earned upon a change of control under the Long-Term Performance-Based Incentive Plan.

William E. Schneider

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination ($)	Not for Cause Termination ($)	For Cause Termination ($)	Death ($)	Disability ($)	Not for Cause or Good Reason Termination Following Change of Control ($)	Change of Control (Without Termination) ($)
Compensation:							
Base Salary						1,342,200	
Short-term Incentive						2,326,480(1)	290,810(2)
2009-2011 Performance Shares						458,615	458,615
2010-2012 Performance Shares	258,986	258,986		258,986	258,986	388,479	388,479
2011-2013 Performance Shares						429,341	429,341
Benefits and Perquisites:							
Regular SISP(3)	2,919,232	2,919,232			2,919,232	2,919,232	
Excess SISP	46,259(4)	46,259(4)			46,259(4)	46,259(5)	
SISP Death Benefits(6)				6,198,875			
Outplacement Services						50,000	
280G Tax(7)						784,127	
Total	**3,224,477**	**3,224,477**		**6,457,861**	**3,224,477**	**8,744,733**	**1,567,245**

(1) Includes the prorated annual incentive for the year of termination, which is the full annual incentive since we assume termination occurred on December 31, 2011, and the additional severance payment of three times the annual incentive. For each of these, we used the higher of (1) the annual incentive earned in 2011 or (2) the highest annual incentive paid in 2009, 2010, and 2011.

(2) Represents the target 2011 annual incentive, which would be deemed earned upon change of control under the Long-Term Performance-Based Incentive Plan.

(3) Represents the present value of Mr. Schneider's vested regular SISP benefit as of December 31, 2011, which was $22,850 per month for 15 years, commencing at age 65. Present value was determined using a 4.00% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2011 table. The three additional years of vesting credit assumed for purposes of calculating the additional SISP benefit under Mr. Schneider's change of control agreement would not increase the actuarial present value of his SISP amount.

(4) Represents the present value of all excess SISP benefits Mr. Schneider would be entitled to upon termination of employment under the SISP. Present value was determined using a 4.00% discount rate. The terms of the excess SISP benefit are described following the Pension Benefits for 2011 table.

(5) Represents the present value of all excess SISP benefits Mr. Schneider would be entitled to, calculated with the assumption of three additional years of employment, as provided under Mr. Schneider's change of control agreement. Present value was determined using a 4.00% discount rate. The terms of the excess SISP benefit are described following the Pension Benefits for 2011 table.

(6) Represents the present value of 180 monthly payments of $45,700 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 4.00% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2011 table.

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

Director Compensation for 2011

Name (a)	Fees Earned or Paid in Cash ($) (b)	Stock Awards ($) (c)(1)	Option Awards ($) (d)	Non-Equity Incentive Plan Compensation ($) (e)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (f)	All Other Compensation ($) (g)(2)	Total ($) (h)
Thomas Everist	62,917	110,000	–(3)	–	–	174	173,091
Karen B. Fagg	62,917	110,000	–	–	–	174	173,091
A. Bart Holaday	55,000(4)	110,000	–	–	–	174	165,174
Dennis W. Johnson	67,917	110,000	–	–	–	174	178,091
Thomas C. Knudson	55,000	110,000	–	–	–	674	165,674
Richard H. Lewis	55,000	110,000	–	–	–	174	165,174
Patricia L. Moss	55,000(5)	110,000	–	–	–	174	165,174
Harry J. Pearce	130,000	110,000	–	–	–	174	240,174
John K. Wilson	55,000(6)	110,000	–	–	–	174	165,174

(1) This column reflects the aggregate grant date fair value of 5,450 shares of MDU Resources Group, Inc. stock purchased for our non-employee directors measured in accordance with Financial Accounting Standards Board generally accepted accounting principles for stock based compensation in FASB Accounting Standards Codification Topic 718. The grant date fair value is based on the purchase price of our common stock on the grant date on November 21, 2011, which was $20.181. The $14 in cash paid to each director for the fractional shares is included in the amounts reported in column (c) to this table.

(2) Group life insurance premium of $174 and a matching charitable contribution of $500 for Mr. Knudson.

(3) Mr. Everist had 6,750 stock options outstanding as of December 31, 2011.

(4) Includes $14,997 that Mr. Holaday received in our common stock in lieu of cash.

(5) Includes $54,983 that Ms. Moss received in our common stock in lieu of cash.

(6) Includes $54,983 that Mr. Wilson received in our common stock in lieu of cash.

Effective June 1, 2011, the board approved changes to the MDU Resources Group, Inc. Directors' Compensation Policy. The following table shows the cash and stock retainers payable to our non-employee directors.

	Effective June 1, 2011	Prior to June 1, 2011
Base Retainer	$55,000	$55,000
Additional Retainers:		
Non-Executive Chairman	75,000	75,000
Lead Director, if any	33,000	33,000
Audit Committee Chairman	15,000	10,000
Compensation Committee Chairman	10,000	5,000
Nominating and Governance Committee Chairman	10,000	5,000
Annual Stock Grant(1)	110,000	4,050 shares

(1) Effective for 2011, the annual stock grant was changed from a fixed number of shares to a grant of shares equal in value to $110,000.

There are no meeting fees.

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

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

Directors are reimbursed for all reasonable travel expenses including spousal expenses in connection with attendance at meetings of the board and its committees. All amounts together with any other perquisites were below the disclosure threshold for 2011.

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

The board revised our stock ownership policy for directors in November 2010. Each director is required, rather than expected, to own our common stock equal in value to five times the director's base retainer. Shares acquired through purchases on the open market and participation in our director stock plans will be considered in ownership calculations as will ownership of our common stock by a spouse. A director is allowed five years commencing January 1 of the year following the year of that director's initial election to the board to meet the requirements. The level of common stock ownership is monitored with an annual report made to the compensation committee of the board. For stock ownership, please see "Security Ownership."

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

BALANCE SHEET

Year: 2011

	Account Number & Title		Last Year	This Year	% Change
1		**Assets and Other Debits**			
2	Utility Plant				
3	101	Electric Plant in Service	$940,549,718	$974,054,986	3.56%
4	101.1	Property Under Capital Leases			
5	102	Electric Plant Purchased or Sold			
6	104	Electric Plant Leased to Others			
7	105	Electric Plant Held for Future Use			
8	106	Completed Constr. Not Classified - Electric			
9	107	Construction Work in Progress - Electric	20,897,466	29,200,954	39.73%
10	108	(Less) Accumulated Depreciation	(438,372,147)	(455,960,812)	4.01%
11	111	(Less) Accumulated Amortization	(5,618,885)	(6,147,613)	9.41%
12	114	Electric Plant Acquisition Adjustments	10,387,642	10,387,642	0.00%
13	115	(Less) Accum. Amort. Electric Plant Acq. Adj.	(9,691,080)	(9,919,323)	2.36%
14	120	Nuclear Fuel (Net)			
15		Other Utility Plant	415,684,337	438,652,088	5.53%
16		Accum. Depr. and Amort. - Other Utl. Plant	(220,060,340)	(227,064,927)	3.18%
17		**TOTAL Utility Plant**	$713,776,711	$753,202,995	5.52%
18	**Other Property & Investments**				
19	121	Nonutility Property	$4,168,474	$4,345,368	4.24%
20	122	(Less) Accum. Depr. & Amort. of Nonutil. Prop.	(1,311,967)	(1,460,122)	11.29%
21	123	Investments in Associated Companies			
22	123.1	Investments in Subsidiary Companies	2,336,133,125	2,402,890,906	2.86%
23	124	Other Investments	48,037,819	47,834,766	-0.42%
24	125	Sinking Funds			
25		**TOTAL Other Property & Investments**	$2,387,027,451	$2,453,610,918	2.79%
26	**Current & Accrued Assets**				
27	131	Cash	$6,238,148	$6,845,910	9.74%
28	132-134	Special Deposits	1,200	1,200	0.00%
29	135	Working Funds	36,865	54,764	48.55%
30	136	Temporary Cash Investments			
31	141	Notes Receivable			
32	142	Customer Accounts Receivable	29,395,116	26,202,128	-10.86%
33	143	Other Accounts Receivable	4,363,648	2,785,945	-36.16%
34	144	(Less) Accum. Provision for Uncollectible Accts.	(231,003)	(237,599)	2.86%
35	145	Notes Receivable - Associated Companies			
36	146	Accounts Receivable - Associated Companies	27,836,855	28,733,840	3.22%
37	151	Fuel Stock	5,029,867	5,921,977	17.74%
38	152	Fuel Stock Expenses Undistributed			
39	153	Residuals and Extracted Products			
40	154	Plant Materials and Operating Supplies	10,139,125	14,611,115	44.11%
41	155	Merchandise	876,220	915,028	4.43%
42	156	Other Material & Supplies			
43	163	Stores Expense Undistributed	(639)	0	100.00%
44	164.1	Gas Stored Underground - Current	18,538,439	21,147,886	14.08%
45	165	Prepayments	4,438,120	4,929,924	11.08%
46	166	Advances for Gas Explor., Devl. & Production			
47	171	Interest & Dividends Receivable			
48	172	Rents Receivable			
49	173	Accrued Utility Revenues	37,326,027	31,824,896	-14.74%
50	174	Miscellaneous Current & Accrued Assets			
51		**TOTAL Current & Accrued Assets**	$143,987,988	$143,737,014	-0.17%

BALANCE SHEET

Year: 2011

	Account Number & Title		Last Year	This Year	% Change
1	**Assets and Other Debits (cont.)**				
2					
3	**Deferred Debits**				
4					
5	181	Unamortized Debt Expense	$1,126,622	$1,046,963	-7.07%
6	182.1	Extraordinary Property Losses			
7	182.2	Unrecovered Plant & Regulatory Study Costs	7,564,400	8,953,457	18.36%
8	182.3	Other Regulatory Assets	86,467,267	123,145,685	42.42%
9	183	Prelim. Electric Survey & Investigation Chrg.	321,479	1,311,495	307.96%
10	183.1	Prelim. Nat. Gas Survey & Investigation Chrg.			
11	183.2	Other Prelim. Nat. Gas Survey & Invtg. Chrgs.			
12	184	Clearing Accounts	109,955	141,904	29.06%
13	185	Temporary Facilities			
14	186	Miscellaneous Deferred Debits	25,010,265	28,845,868	15.34%
15	187	Deferred Losses from Disposition of Util. Plant			
16	188	Research, Devel. & Demonstration Expend.			
17	189	Unamortized Loss on Reacquired Debt	9,565,612	8,846,102	-7.52%
18	190	Accumulated Deferred Income Taxes	59,053,683	65,712,445	11.28%
19	191	Unrecovered Purchased Gas Costs	2,110,509	2,622,263	24.25%
20	192.1	Unrecovered Incremental Gas Costs			
21	192.2	Unrecovered Incremental Surcharges			
22		**TOTAL Deferred Debits**	$191,329,792	$240,626,182	25.77%
23					
24	**TOTAL ASSETS & OTHER DEBITS**		$3,436,121,942	$3,591,177,109	4.51%

	Account Number & Title		Last Year	This Year	% Change
25	**Liabilities and Other Credits**				
26					
27	**Proprietary Capital**				
28					
29	201	Common Stock Issued	$188,901,379	$189,332,485	0.23%
30	202	Common Stock Subscribed			
31	204	Preferred Stock Issued	15,000,000	15,000,000	0.00%
32	205	Preferred Stock Subscribed			
33	207	Premium on Capital Stock	1,030,458,868	1,039,849,252	0.91%
34	211	Miscellaneous Paid-In Capital			
35	213	(Less) Discount on Capital Stock			
36	214	(Less) Capital Stock Expense	(4,110,305)	(4,110,305)	0.00%
37	216	Appropriated Retained Earnings	492,507,658	505,281,931	2.59%
38	216.1	Unappropriated Retained Earnings	1,004,931,088	1,080,840,155	7.55%
39	217	(Less) Reacquired Capital Stock	(3,625,813)	(3,625,813)	0.00%
40	219	Accumulated Other Comprehensive Income	(31,261,155)	(47,000,996)	-50.35%
41		**TOTAL Proprietary Capital**	$2,692,801,720	$2,775,566,709	3.07%
42					
43	**Long Term Debt**				
44					
45	221	Bonds	$280,000,000	$280,000,000	0.00%
46	222	(Less) Reacquired Bonds			
47	223	Advances from Associated Companies			
48	224	Other Long Term Debt	995,927	888,853	-10.75%
49	225	Unamortized Premium on Long Term Debt			
50	226	(Less) Unamort. Discount on Long Term Debt-Dr.			
51		**TOTAL Long Term Debt**	$280,995,927	$280,888,853	-0.04%

BALANCE SHEET

Year: 2011

	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	$936,497	$568,573	-39.29%
9	228.3	Accumulated Provision for Pensions & Benefits	54,957,735	73,404,001	33.56%
10	228.4	Accumulated Misc. Operating Provisions			
11	229	Accumulated Provision for Rate Refunds	0	640,000	
12	230	Asset Retirement Obligations	6,314,471	6,645,275	5.24%
13		**TOTAL Other Noncurrent Liabilities**	$62,208,703	$81,257,849	30.62%
14					
15	**Current & Accrued Liabilities**				
16					
17	231	Notes Payable	$20,000,000	$0	-100.00%
18	232	Accounts Payable	34,271,793	36,325,957	5.99%
19	233	Notes Payable to Associated Companies			
20	234	Accounts Payable to Associated Companies	9,445,305	4,867,683	-48.46%
21	235	Customer Deposits	2,019,003	1,926,012	-4.61%
22	236	Taxes Accrued	5,133,221	18,303,603	256.57%
23	237	Interest Accrued	4,928,786	4,928,205	-0.01%
24	238	Dividends Declared	30,772,550	31,794,172	3.32%
25	239	Matured Long Term Debt			
26	240	Matured Interest			
27	241	Tax Collections Payable	1,963,158	1,660,047	-15.44%
28	242	Miscellaneous Current & Accrued Liabilities	23,267,497	21,988,799	-5.50%
29	243	Obligations Under Capital Leases - Current			
30		**TOTAL Current & Accrued Liabilities**	$131,801,313	$121,794,478	-7.59%
31					
32	**Deferred Credits**				
33					
34	252	Customer Advances for Construction	$7,133,209	$8,440,494	18.33%
35	253	Other Deferred Credits	88,934,756	108,892,007	22.44%
36	254	Other Regulatory Liabilities	8,088,640	10,003,775	23.68%
37	255	Accumulated Deferred Investment Tax Credits	797,879	871,217	9.19%
38	256	Deferred Gains from Disposition Of Util. Plant			
39	257	Unamortized Gain on Reacquired Debt			
40	281-283	Accumulated Deferred Income Taxes	163,359,795	203,461,727	24.55%
41		**TOTAL Deferred Credits**	$268,314,279	$331,669,220	23.61%
42					
43	**TOTAL LIABILITIES & OTHER CREDITS**		$3,436,121,942	$3,591,177,109	4.51%

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Ye
MDU Resources Group, Inc.	(1) X An Original (2) _ A Resubmission	12/31/2011	2011/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

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, pipeline and energy services, exploration and production, construction materials and contracting, construction services and other. The electric, natural gas distribution, and pipeline and energy services businesses are substantially all regulated. Exploration and production, construction materials and contracting, construction services and other are nonregulated. For further descriptions of the Company's businesses, see Note 15. The statements also include the ownership interests in the assets, liabilities and expenses of jointly owned electric generating facilities.

The financial statements were prepared in accordance with the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America. These requirements differ from generally accepted accounting principles (GAAP) related to the presentation of certain items including, but not limited to, the current portion of long-term debt, deferred income taxes, cost of removal liabilities, and current unrecovered purchased gas costs.

The Respondent owns two wholly owned subsidiaries, Centennial Energy Holdings, Inc. and MDU Energy Capital, LLC. As required by the FERC for Form 1 report purposes, MDU Resources Group, Inc. reports its subsidiary investments using the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiaries, as required by GAAP. If GAAP were followed, utility plant, other property and investments would increase by $1.2 billion; current and accrued assets would increase by $1.1 billion; deferred debits would increase by $726.4 million; long-term debt would increase by $1.0 billion; other noncurrent liabilities and current and accrued liabilities would increase by $695.7 million; deferred credits would increase by $1.3 billion as of December 31, 2011. Furthermore, operating revenues would increase by $3.5 billion and operating expenses, excluding income taxes, would increase by $3.2 billion for the twelve months ended December 31, 2011. In addition, net cash provided by operating activities would increase by $407.3 million; net cash used in investing activities would increase by $384.1 million; net cash used in financing activities would increase by $82.8 million; the effect of exchange rate changes on cash would decrease by $214,000; and the net change in cash and cash equivalents would be a decrease of $59.9 million for the twelve months ended December 31, 2011. Reporting its subsidiary investments using the equity method rather than GAAP has no effect on net income or retained earnings.

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

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

The Company's regulated businesses account for certain income and expense items under the provisions of regulatory accounting, which requires these businesses to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense or income, respectively, based on the expected regulatory treatment in future rates. The expected recovery or flowback of these deferred items generally is based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistently with the regulatory treatment established by the FERC and the applicable state public service commissions. See Note 6 for more information regarding the nature and amounts of these regulatory deferrals.

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

Management has also evaluated the impact of events occurring after December 31, 2011, up to the date of issuance of these consolidated financial statements.

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.

Accounts receivable and allowance for doubtful accounts

Accounts receivable consists primarily of trade receivables from the sale of goods and services which are recorded at the invoiced amount net of allowance for doubtful accounts, and costs and estimated earnings in excess of billings on uncompleted contracts. The total balance of receivables past due 90 days or more was $29.8 million and $21.6 million as of December 31, 2011 and 2010, respectively. For more information, see Percentage-of-completion method in this note.

The allowance for doubtful accounts is determined through a review of past due balances and other specific account data. Account balances are written off when management determines the amounts to be uncollectible. The Company's allowance for doubtful accounts as of December 31, 2011 and 2010, was $12.4 million and $15.3 million, respectively.

Inventories and natural gas in storage

Inventories, other than natural gas in storage for the Company's regulated operations, were stated at the lower of average cost or market value. Natural gas in storage for the Company's regulated operations is generally carried at average cost, or cost using the last-in, first-out method. The portion of the cost of natural gas in storage expected to be used within one year was included in inventories. Inventories at December 31 consisted of:

	2011	2010
	(In thousands)	
Aggregates held for resale	$ 78,518	$ 79,894
Materials and supplies	61,611	57,324
Natural gas in storage (current)	36,578	34,557
Asphalt oil	32,335	25,234
Merchandise for resale	32,165	30,182
Other	32,998	25,706
Total	$ 274,205	$ 252,897

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, was included in other assets and was $50.3 million and $48.0 million at December 31, 2011 and 2010, respectively.

Investments

The Company's investments include its equity method investments as discussed in Note 4, the cash surrender value of life insurance policies, an insurance investment contract, auction rate securities, mortgage-backed securities and U.S. Treasury securities. Under the equity method, investments are initially recorded at cost and adjusted for dividends and undistributed earnings and losses. The Company has elected to measure its investment in the insurance investment contract at fair value with any unrealized gains and losses recorded on the Consolidated Statements of Income. The Company has not elected the fair value option for its auction rate securities, mortgage-backed securities and U.S. Treasury securities. For more information, see Notes 8 and 16.

Property, plant and equipment

Additions to property, plant and equipment are recorded at cost. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost of the asset is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, except for exploration and 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 $15.1 million, $17.6 million and $17.4 million in 2011, 2010 and 2009, respectively. Generally, property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except for depletable aggregate reserves, which are depleted based on the units-of-production method, and exploration and production properties, which are amortized on the units-of-production method based on total reserves. The Company collects removal costs for plant assets in regulated utility rates. These amounts are recorded as regulatory liabilities, which are included in other liabilities.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	
MDU Resources Group, Inc.	(1) X An Original (2) _ A Resubmission	12/31/2011	2011/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

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

	2011	2010	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Regulated:			
Electric:			
Generation	$ 546,783	$ 538,071	47
Distribution	255,232	243,205	36
Transmission	179,580	161,972	44
Other	86,929	83,786	13
Natural gas distribution:			
Distribution	1,257,360	1,223,239	38
Other	311,506	285,606	23
Pipeline and energy services:			
Transmission	386,227	357,395	52
Gathering	42,378	41,931	19
Storage	41,908	33,967	51
Other	36,179	33,938	29
Nonregulated:			
Pipeline and energy services:			
Gathering	198,864	203,064	17
Other	13,735	13,512	10
Exploration and production:			
Natural gas and oil properties	2,577,576	2,320,967	*
Other	37,570	35,971	9
Construction materials and contracting:			
Land	126,790	124,018	—
Buildings and improvements	67,627	65,003	20
Machinery, vehicles and equipment	902,136	899,365	12
Construction in progress	8,085	4,879	—
Aggregate reserves	395,214	393,110	**
Construction services:			
Land	4,706	4,526	—
Buildings and improvements	15,001	14,101	22
Machinery, vehicles and equipment	95,891	94,252	7
Other	9,198	10,061	4
Other:			
Land	2,837	2,837	—
Other	46,910	29,727	24
Less accumulated depreciation, depletion and amortization	3,361,208	3,103,323	
Net property, plant and equipment	$ 4,285,014	$ 4,115,180	

* *Amortized on the units-of-production method based on total proved reserves at an Mcf equivalent average rate of $2.04, $1.77 and $1.64 for the years ended December 31, 2011, 2010 and 2009, respectively. Includes natural gas and oil properties accounted for under the full-cost method, of which $232.5 and $182.4 million were excluded from amortization at December 31, 2011 and 2010, respectively.*

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

Impairment of long-lived assets
The Company reviews the carrying values of its long-lived assets, excluding goodwill and natural gas and oil properties, whenever events or changes in circumstances indicate that such carrying values may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. No significant impairment losses were recorded in 2011, 2010 and 2009. Unforeseen events and changes in circumstances could require the recognition of impairment losses at some future date.

Goodwill
Goodwill represents the excess of the purchase price over the fair value of identifiable net tangible and intangible assets acquired in a business combination. Goodwill is required to be tested for impairment annually, which is completed in the fourth quarter, or more frequently if events or changes in circumstances indicate that goodwill may be impaired.

The goodwill impairment test is a two-step process performed at the reporting unit level. The first step of the impairment test involves comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach and a combination of comparable transaction multiples and peer multiples for the market approach. If the fair value of a reporting unit is less than its carrying value, step two of the goodwill impairment test is performed to determine the amount of the impairment loss, if any. The impairment is computed by comparing the implied fair value of the affected reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 2011, 2010 and 2009, the fair value of each reporting unit exceeded the respective carrying value and no impairment losses were recorded. For more information on goodwill, see Note 5.

Natural gas and oil properties
The Company uses the full-cost method of accounting for its natural gas and oil production activities. Under this method, all costs incurred in the acquisition, exploration and development of natural gas and oil properties are capitalized and amortized on the units-of-production method based on total proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are generally treated as adjustments to the cost of the properties with no gain or loss recognized.

Capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net cash flows from proved reserves discounted at 10 percent, as mandated under the rules of the SEC, plus the cost of unproved properties not subject to amortization, less applicable income taxes. Future net revenue was estimated based on end-of-quarter spot market prices adjusted for contracted price changes prior to the fourth quarter of 2009. Effective December 31, 2009, the Modernization of Oil and Gas Reporting rules issued by the SEC changed the pricing used to estimate reserves and associated future cash flows to SEC Defined Prices. Prior to that date, if capitalized costs exceeded the full-cost ceiling at the end of any quarter, a permanent noncash write-down was required to be charged to earnings in that quarter unless subsequent price changes eliminated or reduced an indicated write-down. Effective December 31, 2009, if capitalized costs exceed the full-cost ceiling at the end of any quarter, a permanent noncash write-down is required to be charged to earnings in that quarter regardless of subsequent price changes.

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

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

At December 31, 2011, 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, 2011, 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, 2011, in total and by the year in which such costs were incurred:

		Year Costs Incurred			
	Total	2011	2010	2009	2008 and prior
			(In thousands)		
Acquisition	$ 185,773	$ 50,721	$ 71,315	$ 988	$ 62,749
Development	9,938	9,689	156	2	91
Exploration	27,439	24,389	2,710	72	268
Capitalized interest	9,312	3,539	3,096	44	2,633
Total costs not subject to amortization	$ 232,462	$ 88,338	$ 77,277	$ 1,106	$ 65,741

Costs not subject to amortization as of December 31, 2011, consisted primarily of unevaluated leaseholds and development costs in the Bakken area, Texas properties, Niobrara play, the Paradox Basin, the Green River Basin and the Big Horn Basin. The Company expects that the majority of these costs will be evaluated within the next five years and included in the amortization base as the properties are evaluated and/or developed.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The Company recognizes utility revenue each month based on the services provided to all utility customers during the month. Accrued unbilled revenue which is included in receivables, net, represents revenues recognized in excess of amounts billed. Accrued unbilled revenue at Montana-Dakota, Cascade and Intermountain was $80.2 million and $87.3 million at December 31, 2011 and 2010, respectively. The Company recognizes construction contract revenue at its construction businesses using the percentage-of-completion method as discussed later. The Company recognizes revenue from exploration and production properties only on that portion of production sold and allocable to the Company's ownership interest in the related properties. The Company recognizes all other revenues when services are rendered or goods are delivered. The Company presents revenues net of taxes collected from customers at the time of sale to be remitted to governmental authorities, including sales and use taxes.

Percentage-of-completion method
The Company recognizes construction contract revenue from fixed-price and modified fixed-price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. If a loss is anticipated on a contract, the loss is immediately recognized. Costs and estimated earnings in excess of billings on uncompleted contracts of $54.3 million and $46.6 million at December 31, 2011 and 2010, respectively, represent revenues recognized in excess of amounts billed and were included in receivables, net. Billings in excess of costs and estimated earnings on uncompleted contracts of $79.1 million and $65.2 million at December 31, 2011 and 2010, respectively, represent billings in excess of revenues recognized and were included in accounts payable. Amounts representing balances billed but not paid by customers under retainage provisions in contracts amounted to $51.5 million and $51.1 million at December 31, 2011 and 2010, respectively. The amounts expected to be paid within one year or less are included in receivables, net, and amounted to $49.3 million and $50.4 million at December 31, 2011 and 2010, respectively. The long-term retainage which was included in deferred charges and other assets - other was $2.2 million and $700,000 at December 31, 2011 and 2010, respectively.

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

The Company's policy generally allows the hedging of monthly forecasted sales of natural gas and oil production at Fidelity for a period up to 36 months from the time the Company enters into the hedge. The Company's policy requires that interest rate derivative instruments not exceed a period of 24 months and foreign currency derivative instruments not exceed a 12-month period. The Company's policy allows the hedging of monthly forecasted purchases of natural gas at Cascade and Intermountain for a period up to three years.

The Company's policy requires that each month as physical natural gas and oil production at Fidelity occurs and the commodity is sold, the related portion of the derivative agreement for that month's production must settle with its counterparties. Settlements represent the exchange of cash between the Company and its counterparties based on the notional quantities and prices for each month's physical delivery as specified within the agreements. The fair value of the remaining notional amounts on the derivative agreements is recorded on the balance sheet as an asset or liability measured at fair value. The Company's policy also requires settlement of natural gas derivative instruments at Cascade and Intermountain monthly and all interest rate derivative transactions must be settled over a period that will not exceed 90 days, and any foreign currency derivative transaction settlement periods may not exceed a 12-month period. The Company has policies and procedures that management believes minimize credit-risk exposure. Accordingly, the Company does not anticipate any material effect on its financial position or results of operations as a result of nonperformance by counterparties. For more information on derivative instruments, see Note 7.

The Company's swap and collar agreements are reflected at fair value. For more information, see Note 8.

Asset retirement obligations
The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the Company capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over

time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company either settles the obligation for the recorded amount or incurs a gain or loss at its nonregulated operations or incurs a regulatory asset or liability at its regulated operations. For more information on asset retirement obligations, see Note 10.

Legal costs
The Company expenses external legal fees as they are incurred.

Natural gas costs recoverable or refundable through rate adjustments
Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within a period ranging from 12 to 28 months from the time such costs are paid. Natural gas costs refundable through rate adjustments were $45.1 million and $37.0 million at December 31, 2011 and 2010, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $2.6 million and $6.6 million at December 31, 2011 and 2010, respectively, which is included in prepayments and other current assets.

Insurance
Certain subsidiaries of the Company are insured for workers' compensation losses, subject to deductibles ranging up to $1 million per occurrence. Automobile liability and general liability losses are insured, subject to deductibles ranging up to $1 million per accident or occurrence. These subsidiaries have excess coverage above the primary automobile and general liability policies on a claims first-made and reported basis beyond the deductible levels. The subsidiaries of the Company are retaining losses up to the deductible amounts accrued on the basis of estimates of liability for claims incurred and for claims incurred but not reported.

Income taxes
The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities. Excess deferred income tax balances associated with the Company's rate-regulated activities have been recorded as a regulatory liability and are included in other liabilities. These regulatory liabilities are expected to be reflected as a reduction in future rates charged to customers in accordance with applicable regulatory procedures.

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

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

Foreign currency translation adjustment
The functional currency of the Company's investment in ECTE, as further discussed in Note 4, is the Brazilian Real. Translation from the Brazilian Real to the U.S. dollar for assets and liabilities is performed using the exchange rate in effect at the balance sheet date. Revenues and expenses are translated on a year-to-date basis using an average of the daily exchange rates. Adjustments resulting from such translations are reported as a separate component of other comprehensive income (loss) in common stockholders' equity.

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

Earnings (loss) per common share

Basic earnings (loss) per common share were computed by dividing earnings (loss) on common stock by the weighted average number of shares of common stock outstanding during the year. Diluted earnings per common share were computed by dividing earnings on common stock by the total of the weighted average number of shares of common stock outstanding during the year, plus the effect of outstanding stock options, restricted stock grants and performance share awards. In 2011 and 2010, there were no shares excluded from the calculation of diluted earnings per share. Common stock outstanding includes issued shares less shares held in treasury. Net income was the same for both the basic and diluted earnings per share calculations. A reconciliation of the weighted average common shares outstanding used in the basic and diluted earnings per share calculation was as follows:

	2011	2010	2009*
	(In thousands)		
Weighted average common shares outstanding - basic	188,763	188,137	185,175
Effect of dilutive stock options and performance share awards	142	92	—
Weighted average common shares outstanding - diluted	188,905	188,229	185,175

* *Due to the loss on common stock, 825 outstanding stock options, 18 restricted stock grants and 656 performance share awards were excluded from the computation of diluted loss per common share as their effect was antidilutive.*

Use of estimates

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

Cash flow information

Cash expenditures for interest and income taxes were as follows:

Years ended December 31,	2011	2010	2009
	(In thousands)		
Interest, net of amount capitalized	$ 78,133	$ 80,962	$ 81,267
Income taxes paid (refunded), net	$ (12,287)	$ 46,892	$ 39,807

For the year ended December 31, 2011, cash flows from investing activities do not include $24.0 million of capital expenditures, including amounts being financed with accounts payable, and therefore, do not have an impact on cash flows for the period.

New accounting standards

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

Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs In May 2011, the FASB issued guidance on fair value measurement and disclosure requirements. The guidance generally clarifies the application of existing requirements on topics including the concepts of highest and best use and valuation premise and disclosing quantitative information about the unobservable inputs used in the measurement of instruments categorized within Level 3 of the fair value hierarchy. Additionally, the guidance includes changes on topics such as measuring fair value of financial instruments that are managed within a portfolio and additional disclosure for fair value measurements categorized within Level 3 of the fair value hierarchy. This guidance is effective for the Company on January 1, 2012. The guidance will require additional disclosures, but it will not impact the Company's results of operations, financial position or cash flows.

Presentation of Comprehensive Income In June 2011, the FASB issued guidance on the presentation of comprehensive income. This guidance eliminates the option of presenting components of other comprehensive income as part of the statement of stockholders' equity. The guidance will allow the Company the option to present the total of comprehensive income, the components of net income and the components of other comprehensive income in either a single continuous statement of comprehensive income or in two separate but consecutive statements. In December 2011, the FASB indefinitely deferred the effective date for the guidance related to the presentation of reclassifications of items out of accumulated other comprehensive income by component in both the statement in which net income is presented and the statement in which other comprehensive income is presented. The guidance, except for the portion that was indefinitely deferred, is effective for the Company on January 1, 2012, and must be applied retrospectively. The Company is evaluating the effects of this guidance on disclosure, but it will not impact the Company's results of operations, financial position or cash flows.

Disclosures about an Employer's Participation in a Multiemployer Plan In September 2011, the FASB issued guidance on an employer's participation in multiemployer benefit plans. The guidance was issued to enhance the transparency of disclosures about the significant multiemployer plans in which employers participate, the level of the employer's participation in those plans, the financial health of the plans and the nature of the employer's commitments to the plans. This guidance was effective for the Company on December 31, 2011, and must be applied retrospectively. The guidance required additional disclosures, but it did not impact the Company's results of operations, financial position or cash flows.

Comprehensive income (loss)

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

The components of other comprehensive loss, and their related tax effects for the years ended December 31 were as follows:

	2011	2010	2009
		(In thousands)	
Other comprehensive loss:			
Net unrealized gain (loss) on derivative instruments qualifying as hedges:			
Net unrealized gain (loss) on derivative instruments arising during the period, net of tax of $4,683, $(1,867) and $(2,509) in 2011, 2010 and 2009, respectively	$ 7,900	$ (3,077)	$ (4,094)
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $0, $(2,305) and $29,170 in 2011, 2010 and 2009, respectively	—	(3,750)	47,590
Net unrealized gain (loss) on derivative instruments qualifying as hedges	7,900	673	(51,684)
Postretirement liability adjustment, net of tax of $(13,573), $(3,609) and $6,291 in 2011, 2010 and 2009, respectively	(22,427)	(5,730)	9,918
Foreign currency translation adjustment, net of tax of $(832), $(3,486) and $6,814 in 2011, 2010 and 2009, respectively	(1,295)	(5,371)	10,568
Net unrealized gains on available-for-sale investments, net of tax of $44 in 2011	82	—	—
Total other comprehensive loss	$ (15,740)	$ (10,428)	$ (31,198)

The after-tax components of accumulated other comprehensive loss as of December 31, 2011, 2010 and 2009, were as follows:

	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Postretirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gains on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
			(In thousands)		
Balance at December 31, 2009	$ (2,298)	$ (25,163)	$ 6,628	$ —	$ (20,833)
Balance at December 31, 2010	$ (1,625)	$ (30,893)	$ 1,257	$ —	$ (31,261)
Balance at December 31, 2011	**$ 6,275**	**$ (53,320)**	**$ (38)**	**$ 82**	**$ (47,001)**

Note 2 - Acquisitions

In 2011, a purchase price adjustment, consisting of the Company's common stock and cash, of $298,000 was made with respect to an acquisition made prior to 2011.

In 2010, the Company acquired natural gas properties in the Green River Basin in southwest Wyoming. The total purchase consideration for these properties and purchase price adjustments with respect to certain other acquisitions made prior to 2010, consisting of the Company's common stock and cash, was $106.4 million.

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

The acquisitions were accounted for under the acquisition method of accounting and, accordingly, the acquired assets and liabilities assumed have been recorded at their respective fair values as of the date of acquisition. 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 acquisitions are not presented, as such acquisitions were not material to the Company's financial position or results of operations.

Note 3 - Discontinued Operations

In 2007, Centennial Resources sold CEM to Bicent. In connection with the sale, Centennial Resources agreed to indemnify Bicent and its affiliates from certain third party claims arising out of or in connection with Centennial Resources' ownership or operation of CEM prior to the sale. In addition, Centennial had previously guaranteed CEM's obligations under a construction contract. In the fourth quarter of 2011, the Company accrued $21.0 million ($13.0 million after tax) related to the guarantee as a result of an arbitration award against CEM. In 2011, the Company also incurred legal expenses related to this matter and in the first quarter had an income tax benefit related to favorable resolution of certain tax matters. In the fourth quarter of 2010, the Company established an accrual for an indemnification claim by Bicent. These items are reflected as discontinued operations in the consolidated financial statements and accompanying notes. Discontinued operations are included in the Other category. For further information, see Note 19.

Note 4 - Equity Method Investments

Investments in companies in which the Company has the ability to exercise significant influence over operating and financial policies are accounted for using the equity method. The Company's equity method investments at December 31, 2011 and 2010, include ECTE.

In August 2006, MDU Brasil acquired ownership interests in the Brazilian Transmission Lines. The electric transmission lines are primarily in northeastern and southern Brazil. The transmission contracts provide for revenues denominated in the Brazilian Real, annual inflation adjustments and change in tax law adjustments. The functional currency for the Brazilian Transmission Lines is the Brazilian Real.

In 2009, multiple sales agreements were signed with three separate parties for the Company to sell its ownership interests in the Brazilian Transmission Lines. In November 2010, the Company completed the sale and recognized a gain of $22.7 million ($13.8 million after tax). The Company's entire ownership interest in ENTE and ERTE and 59.96 percent of the Company's ownership interest in ECTE was sold. The remaining interest in ECTE is being purchased by one of the parties over a four-year period. In November 2011, the Company completed the sale of one-fourth of the remaining interest and recognized a gain of $1.0 million ($600,000 after tax). The gains are recorded in earnings from equity method investments on the Consolidated Statements of Income. Alusa, CEMIG and CELESC hold the remaining ownership interests in ECTE.

At December 31, 2011 and 2010, the Company's equity method investments had total assets of $111.1 million and $107.4 million, respectively, and long-term debt of $37.1 million and $30.1 million, respectively. The Company's investment in its equity method investments was approximately $9.2 million and $10.9 million, including undistributed earnings of $3.7 million and $1.9 million, at December 31, 2011 and 2010, respectively.

Note 5 - Goodwill and Other Intangible Assets

The changes in the carrying amount of goodwill for the year ended December 31, 2011, were as follows:

	Balance as of January 1, 2011*	Goodwill Acquired During the Year**	Balance as of December 31, 2011*
		(In thousands)	
Electric	$ —	$ —	$ —
Natural gas distribution	345,736	—	345,736
Pipeline and energy services	9,737	—	9,737
Exploration and production	—	—	—
Construction materials and contracting	176,290	—	176,290
Construction services	102,870	298	103,168
Other	—	—	—
Total	$ 634,633	$ 298	$ 634,931

* *Balance is presented net of accumulated impairment of $12.3 million at the pipeline and energy services segment, which occurred in prior periods.*

** *Includes a purchase price adjustment that was not material related to an acquisition in a prior period.*

The changes in the carrying amount of goodwill for the year ended December 31, 2010, were as follows:

	Balance as of January 1, 2010*	Goodwill Acquired During the Year**	Balance as of December 31, 2010*
		(In thousands)	
Electric	$ —	$ —	$ —
Natural gas distribution	345,736	—	345,736
Pipeline and energy services	7,857	1,880	9,737
Exploration and production	—	—	—
Construction materials and contracting	175,743	547	176,290
Construction services	100,127	2,743	102,870
Other	—	—	—
Total	$ 629,463	$ 5,170	$ 634,633

* *Balance is presented net of accumulated impairment of $12.3 million at the pipeline and energy services segment, which occurred in prior periods.*

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

Other amortizable intangible assets at December 31 were as follows:

	2011	2010
	(In thousands)	
Customer relationships	$ 21,702	$ 24,942
Accumulated amortization	(10,392)	(11,625)
	11,310	13,317
Noncompete agreements	7,685	9,405
Accumulated amortization	(5,371)	(6,425)
	2,314	2,980
Other	11,442	13,217
Accumulated amortization	(4,223)	(4,243)
	7,219	8,974
Total	$ 20,843	$ 25,271

Amortization expense for intangible assets for the years ended December 31, 2011, 2010 and 2009, was $3.7 million, $4.2 million and $5.0 million, respectively. Estimated amortization expense for intangible assets is $3.8 million in 2012, $3.7 million in 2013, $3.3 million in 2014, $2.6 million in 2015, $2.1 million in 2016 and $5.3 million thereafter.

Note 6 - Regulatory Assets and Liabilities

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

	Estimated Recovery Period*	2011	2010
		(In thousands)	
Regulatory assets:			
Pension and postretirement benefits (a)	(e)	171,492	103,818
Deferred income taxes	**	119,189	114,427
Taxes recoverable from customers (a)	—	12,433	11,961
Plant costs (a)	Over plant lives	10,256	9,964
Long-term debt refinancing costs (a)	Up to 27 years	10,112	11,101
Costs related to identifying generation development (a)	Up to 15 years	9,817	13,777
Natural gas supply derivatives (b)	Up to 1 year	437	9,359
Natural gas cost recoverable through rate adjustments (b)	Up to 28 months	2,622	6,609
Other (a) (b)	Largely within 1 year	22,651	35,225
Total regulatory assets		359,009	316,241
Regulatory liabilities:			
Plant removal and decommissioning costs (c)		289,972	276,652
Deferred income taxes**		84,963	64,017
Natural gas costs refundable through rate adjustments (d)		45,064	36,996
Taxes refundable to customers (c)		31,837	19,352
Other (c) (d)		8,393	16,080
Total regulatory liabilities		460,229	413,097
Net regulatory position		(101,220)	(96,856)

* *Estimated recovery period for regulatory assets currently being recovered in rates charged to customers.*
** *Represents deferred income taxes related to regulatory assets and liabilities. The deferred income tax assets are not earning a rate of return.*
(a) Included in deferred charges and other assets on the Consolidated Balance Sheets.
(b) Included in prepayments and other current assets on the Consolidated Balance Sheets.
(c) Included in other liabilities on the Consolidated Balance Sheets.
(d) Included in other accrued liabilities on the Consolidated Balance Sheets.
(e) Recovered as expense is incurred.

The regulatory assets are expected to be recovered in rates charged to customers. A portion of the Company's regulatory assets are not earning a return; however, these regulatory assets are expected to be recovered from customers in future rates. Excluding deferred income taxes, as of December 31, 2011, approximately $216.4 million of regulatory assets were not earning a rate of return.

If, for any reason, the Company's regulated businesses cease to meet the criteria for application of regulatory accounting for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the balance sheet and included in the statement of income as an extraordinary item in the period in which the discontinuance of regulatory accounting occurs.

Note 7 - Derivative Instruments

Derivative instruments, including certain derivative instruments embedded in other contracts, are required to be recorded on the balance sheet as either an asset or liability measured at fair value. The Company's policy is to not offset fair value amounts for derivative instruments and, as a result, the Company's derivative assets and liabilities are presented gross on the Consolidated Balance Sheets. Changes in the derivative instrument's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. Accounting for qualifying hedges allows derivative gains and losses to offset the related results on the hedged item in the income statement and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

In the event a derivative instrument being accounted for as a cash flow hedge does not qualify for hedge accounting because it is no longer highly effective in offsetting changes in cash flows of a hedged item; if the derivative instrument expires or is sold, terminated or exercised; or if management determines that designation of the derivative instrument as a hedge instrument is no longer appropriate, hedge accounting would be discontinued and the derivative instrument would continue to be carried at fair value with changes in its fair value recognized in earnings. In these circumstances, the net gain or loss at the time of discontinuance of hedge accounting would remain in accumulated other comprehensive income (loss) until the period or periods during which the hedged forecasted transaction affects earnings, at which time the net gain or loss would be reclassified into earnings. In the event a cash flow hedge is discontinued because it is unlikely that a forecasted transaction will occur, the derivative instrument would continue to be carried on the balance sheet at its fair value, and gains and losses that had accumulated in other comprehensive income (loss) would be recognized immediately in earnings. In the event of a sale, termination or extinguishment of a foreign currency derivative, the resulting gain or loss would be recognized immediately in earnings. The Company's policy requires approval to terminate a derivative instrument prior to its original maturity. As of December 31, 2011, the Company had no outstanding foreign currency hedges.

The Company evaluates counterparty credit risk on its derivative assets and the Company's credit risk on its derivative liabilities. As of December 31, 2011 and 2010, credit risk was not material.

Cascade and Intermountain

At December 31, 2011, Cascade held a natural gas swap agreement with total forward notional volumes of 305,000 MMBtu, which was not designated as a hedge. Cascade utilizes, and Intermountain periodically utilizes, natural gas swap agreements to manage a portion of their regulated natural gas supply portfolios in order to manage fluctuations in the price of natural gas related to core customers in accordance with authority granted by the IPUC, WUTC and OPUC. Core customers consist of residential, commercial and smaller industrial customers. The fair value of the derivative instrument must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or a liability. Periodic changes in the fair market value of the derivative instruments are recorded on the Consolidated Balance Sheets as a regulatory asset or a regulatory liability, and settlements of these arrangements are expected to be recovered through the purchased gas cost adjustment mechanism. Gains and losses on the settlements of these derivative instruments are recorded as a component of purchased natural gas sold on the Consolidated Statements of Income as they are recovered through the purchased gas cost adjustment mechanism. Under the terms of these arrangements, Cascade and Intermountain will either pay or receive settlement payments based on the difference between the fixed strike price and the monthly index price applicable to each contract. For the years ended December 31, 2011 and 2010, the change in the fair market value of the derivative instruments of $8.9 million and $18.5 million, respectively, were recorded as a decrease to regulatory assets.

Certain of Cascade's derivative instruments contain credit-risk-related contingent features that permit the counterparties to require collateralization if Cascade's derivative liability positions exceed certain dollar thresholds. The dollar thresholds in certain of Cascade's agreements are determined and may fluctuate based on Cascade's credit rating on its debt. In addition, Cascade's derivative instruments contain cross-default provisions that state if the entity fails to make payment with respect to certain of its indebtedness, in excess of specified amounts, the counterparties could require early settlement or termination of such entity's derivative instruments in liability positions. The aggregate fair value of Cascade's derivative instruments with credit-risk-related contingent features that are in a liability position at December 31, 2011, was $437,000.

The aggregate fair value of assets that would have been needed to settle the instruments immediately if the credit-risk-related contingent features were triggered on December 31, 2011, was $437,000.

Fidelity

At December 31, 2011, Fidelity held natural gas swap agreements with total forward notional volumes of 10.8 million MMBtu, natural gas basis swap agreements with total forward notional volumes of 3.5 million MMBtu, and oil swap and collar agreements with total forward notional volumes of 4.0 million Bbl, all of which were designated as cash flow hedging instruments. Fidelity utilizes these derivative instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and oil and basis differentials on its forecasted sales of natural gas and oil production.

As of December 31, 2011, the maximum term of the derivative instruments, in which the exposure to the variability in future cash flows for forecasted transactions is being hedged, is 24 months.

Centennial

At December 31, 2011, Centennial held interest rate swap agreements with a total notional amount of $60.0 million, which were designated as cash flow hedging instruments. Centennial entered into these interest rate derivative instruments to manage a portion of its interest rate exposure on the forecasted issuance of long-term debt. Centennial's interest rate swap agreements have mandatory termination dates ranging from October 2012 through June 2013.

Fidelity and Centennial

The fair value of the derivative instruments must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or liability. Changes in the fair value attributable to the effective portion of hedging instruments, net of tax, are recorded in stockholders' equity as a component of accumulated other comprehensive income (loss). To the extent that the hedges are not effective, the ineffective portion of the changes in fair market value is recorded directly in earnings.

For the year ended December 31, 2011, $1.8 million (before tax) of hedge ineffectiveness related to natural gas and oil derivative instruments was reclassified as a gain into operating revenues and is reflected on the Consolidated Statements of Income. The amount of hedge ineffectiveness was immaterial for the years ended December 31, 2010 and 2009, and there were no components of the derivative instruments' gain or loss excluded from the assessment of hedge effectiveness. Gains and losses must be reclassified into earnings as a result of the discontinuance of cash flow hedges if it is probable that the original forecasted transactions will not occur. There were no such reclassifications into earnings as a result of the discontinuance of hedges.

Gains and losses on the natural gas and oil derivative instruments are reclassified from accumulated other comprehensive income (loss) into operating revenues on the Consolidated Statements of Income at the date the natural gas and oil quantities are settled. The proceeds received for natural gas and oil production are generally based on market prices. Gains and losses on the interest rate derivatives are reclassified from accumulated other comprehensive income (loss) into interest expense on the Consolidated Statements of Income in the same period the hedged item affects earnings. For further information regarding the gains and losses on derivative instruments qualifying as cash flow hedges that were recognized in other comprehensive income (loss) and the gains and losses reclassified from accumulated other comprehensive income (loss) into earnings, see Note 1.

Based on December 31, 2011, fair values, over the next 12 months net gains of approximately $8.7 million (after tax) are estimated to be reclassified from accumulated other comprehensive income (loss) into earnings, subject to changes in natural gas and oil market prices and interest rates, as the hedged transactions affect earnings.

Certain of Fidelity's and Centennial's derivative instruments contain cross-default provisions that state if Fidelity or any of its affiliates or Centennial fails to make payment with respect to certain indebtedness, in excess of specified amounts, the counterparties could require early settlement or termination of derivative instruments in liability positions. The aggregate fair value of Fidelity's and Centennial's derivative instruments with credit-risk-related contingent features that are in a liability position at December 31, 2011, was $18.4 million. The aggregate fair value of assets that would have been needed to settle the instruments immediately if the credit-risk-related contingent features were triggered on December 31, 2011, was $18.4 million.

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

Asset Derivatives	Location on Consolidated Balance Sheets	Fair Value at December 31, 2011	Fair Value at December 31, 2010
		(In thousands)	
Designated as hedges:			
Commodity derivatives	Commodity derivative instruments	$ 27,687	$ 15,123
	Other assets - noncurrent	2,768	4,104
		30,455	19,227
Not designated as hedges:			
Commodity derivatives	Commodity derivative instruments	—	—
	Other assets - noncurrent	—	—
		—	—
Total asset derivatives		$ 30,455	$ 19,227

Liability Derivatives	Location on Consolidated Balance Sheets	Fair Value at December 31, 2011	Fair Value at December 31, 2010
		(In thousands)	
Designated as hedges:			
Commodity derivatives	Commodity derivative instruments	$ 12,727	$ 15,069
	Other liabilities - noncurrent	937	6,483
Interest rate derivatives	Other accrued liabilities	827	—
	Other liabilities - noncurrent	3,935	—
		18,426	21,552
Not designated as hedges:			
Commodity derivatives	Commodity derivative instruments	437	9,359
	Other liabilities - noncurrent	—	—
		437	9,359
Total liability derivatives		$ 18,863	$ 30,911

Note 8 - Fair Value Measurements

The Company measures its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. The Company anticipates using these investments to satisfy its obligations under its unfunded, nonqualified benefit plans for executive officers and certain key management employees, and invests in these fixed-income and equity securities for the purpose of earning investment returns and capital appreciation. These investments, which totaled $38.4 million and $39.5 million as of December 31, 2011 and 2010, respectively, are classified as Investments on the Consolidated Balance Sheets. The decrease in the fair value of these investments for the year ended December 31, 2011, was $1.1 million (before tax). The increase in the fair value of these investments for the years ended December 31, 2010 and 2009, was $5.8

million (before tax) and $7.1 million (before tax), respectively. The change in fair value, which is considered part of the cost of the plan, is classified in operation and maintenance expense on the Consolidated Statements of Income.

The Company did not elect the fair value option, which records gains and losses in income, for its remaining available-for-sale securities, which include auction rate securities, mortgage-backed securities and U.S. Treasury securities. These available-for-sale securities are recorded at fair value and are classified as Investments on the Consolidated Balance Sheets. The Company's auction rate securities approximate cost and, as a result, there are no accumulated unrealized gains or losses recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets related to these investments. Unrealized gains or losses on mortgage-backed securities and U.S. Treasury securities are recorded in accumulated other comprehensive income (loss) as discussed in Note 1. Details of available-for-sale securities were as follows:

December 31, 2011	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(In thousands)		
Insurance investment contract	$ 31,884	$ 6,468	$ —	$ 38,352
Auction rate securities	11,400	—	—	11,400
Mortgage-backed securities	8,206	95	(5)	8,296
U.S. Treasury securities	1,619	37	—	1,656
Total	$ 53,109	$ 6,600	$ (5)	$ 59,704

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

	Fair Value Measurements at December 31, 2011, Using			
	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Signficant Unobservable Inputs (Level 3)	Balance at December 31, 2011
	(In thousands)			
Assets:				
Money market funds	$ —	$ 97,500	$ —	$ 97,500
Available-for-sale securities:				
Insurance investment contract*	—	38,352	—	38,352
Auction rate securities	—	11,400	—	11,400
Mortgage-backed securities	—	8,296	—	8,296
U.S. Treasury securities	—	1,656	—	1,656
Commodity derivative instruments - current	—	27,687	—	27,687
Commodity derivative instruments - noncurrent	—	2,768	—	2,768
Total assets measured at fair value	$ —	$ 187,659	$ —	$ 187,659
Liabilities:				
Commodity derivative instruments - current	$ —	$ 13,164	$ —	$ 13,164
Commodity derivative instruments - noncurrent	—	937	—	937
Interest rate derivative instruments - current	—	827	—	827
Interest rate derivative instruments - noncurrent	—	3,935	—	3,935
Total liabilities measured at fair value	$ —	$ 18,863	$ —	$ 18,863

* *The insurance investment contract invests approximately 33 percent in common stock of mid-cap companies, 34 percent in common stock of small-cap companies, 32 percent in common stock of large-cap companies and 1 percent in cash and cash equivalents.*

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	
MDU Resources Group, Inc.	(1) X An Original (2) _ A Resubmission	12/31/2011	2011/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

	Fair Value Measurements at December 31, 2010, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2010
	(In thousands)			
Assets:				
Money market funds	$ —	$ 166,620	$ —	$ 166,620
Available-for-sale securities:				
Insurance investment contract*	—	39,541	—	39,541
Auction rate securities	—	11,400	—	11,400
Commodity derivative instruments - current	—	15,123	—	15,123
Commodity derivative instruments - noncurrent	—	4,104	—	4,104
Total assets measured at fair value	$ —	$ 236,788	$ —	$ 236,788
Liabilities:				
Commodity derivative instruments - current	$ —	$ 24,428	$ —	$ 24,428
Commodity derivative instruments - noncurrent	—	6,483	—	6,483
Total liabilities measured at fair value	$ —	$ 30,911	$ —	$ 30,911

* *The insurance investment contract invests approximately 35 percent in common stock of mid-cap companies, 33 percent in common stock of small-cap companies, 31 percent in common stock of large-cap companies and 1 percent in cash and cash equivalents.*

The estimated fair value of the Company's Level 2 money market funds and available-for-sale securities is determined using the market approach. The Level 2 money market funds consist of investments in short-term unsecured promissory notes and the value is based on comparable market transactions taking into consideration the credit quality of the issuer. The estimated fair value of the Company's Level 2 available-for-sale securities is based on comparable market transactions, other observable inputs or other sources, including pricing from outside sources such as the fund itself.

The estimated fair value of the Company's Level 2 commodity derivative instruments is based upon futures prices, volatility and time to maturity, among other things. Counterparty statements are utilized to determine the value of the commodity derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The nonperformance risk of the counterparties in addition to the Company's nonperformance risk is also evaluated.

The estimated fair value of the Company's Level 2 interest rate derivative instruments is measured using quoted market prices or pricing models using prevailing market interest rates as of the measurement date. Counterparty statements are utilized to determine the value of the interest rate derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The nonperformance risk of the counterparties in addition to the Company's nonperformance risk is also evaluated.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2011 and 2010, there were no significant transfers between Levels 1 and 2.

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

	2011		2010	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	**$ 1,424,678**	**$ 1,592,807**	$ 1,506,752	$ 1,621,184

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

Note 9 - Debt

Certain debt instruments of the Company and its subsidiaries, including those discussed below, contain restrictive covenants and cross-default provisions. In order to borrow under the respective credit agreements, the Company and its subsidiaries must be in compliance with the applicable covenants and certain other conditions, all of which the Company and its subsidiaries, as applicable, were in compliance with at December 31, 2011. In the event the Company and its subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

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

Company	Facility	Facility Limit	Amount Outstanding at December 31, 2011	Amount Outstanding at December 31, 2010	Letters of Credit at December 31, 2011	Expiration Date
			(Dollars in millions)			
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement	(a) $ 100.0	$ — (h)	$ 20.0 (b)	$ —	5/26/15
Cascade Natural Gas Corporation	Revolving credit agreement	$ 50.0 (c)	$ —	$ —	$ 1.9 (d)	12/28/12 (e)
Intermountain Gas Company	Revolving credit agreement	$ 65.0 (f)	$ 8.1	$ 20.2	$ —	8/11/13
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement	(g) $ 400.0	$ — (h)	$ — (h)	$ 21.6 (d)	12/13/12

(a) The $125 million commercial paper program is supported by a revolving credit agreement with various banks totaling $100 million (provisions allow for increased borrowings, at the option of the Company on stated conditions, up to a maximum of $150 million). There were no amounts outstanding under the credit agreement.

(b) Amount outstanding under commercial paper program that was classified as short-term borrowings because the revolving credit agreement expired within one year.

(c) Certain provisions allow for increased borrowings, up to a maximum of $75 million.

(d) The outstanding letters of credit, as discussed in Note 19, reduce amounts available under the credit agreement.

(e) Provisions allow for an extension of up to two years upon consent of the banks.

(f) Certain provisions allow for increased borrowings, up to a maximum of $80 million.

(g) The $400 million commercial paper program is supported by a revolving credit agreement with various banks totaling $400 million (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of $450 million). There were no amounts outstanding under the credit agreement.

(h) Amount outstanding under commercial paper program.

The Company's and Centennial's respective commercial paper programs are supported by revolving credit agreements. While the amount of commercial paper outstanding does not reduce available capacity under the respective revolving credit agreements, the Company and Centennial do not issue commercial paper in an aggregate amount exceeding the available capacity under their credit agreements.

The following includes information related to the preceding table.

Short-term borrowings

Centennial Energy Holdings, Inc. Centennial's revolving credit agreement supports its commercial paper program. Any commercial paper borrowings as of December 31, 2011, would have been classified as short-term borrowings because the revolving credit agreement expires within one year. Any commercial paper borrowings as of December 31, 2010, would have been classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings.

Centennial's revolving credit agreement contains customary covenants and provisions, including a covenant of Centennial and certain of its subsidiaries, not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets and on the making of certain loans and investments.

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

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

Cascade's credit agreement contains customary covenants and provisions, including a covenant of Cascade not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Cascade's credit agreement also contains cross-default provisions. These provisions state that if Cascade fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, Cascade will be in default under the credit agreement. Certain of Cascade's financing agreements and Cascade's practices limit the amount of subsidiary indebtedness.

Long-term debt

MDU Resources Group, Inc. On May 26, 2011, the Company entered into a new revolving credit agreement, which replaced the revolving credit agreement that expired on June 21, 2011. The Company's revolving credit agreement supports its commercial paper program. Any commercial paper borrowings under this agreement would be classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings. The commercial paper borrowings outstanding as of December 31, 2010, were classified as short-term borrowings because the previous revolving credit agreement expired within one year.

The credit agreement contains customary covenants and provisions, including covenants of the Company not to permit, as of the end of any fiscal quarter, (A) the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent or (B) the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Other covenants include limitations on the sale of certain assets and on the making of certain loans and investments.

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

Intermountain Gas Company The credit agreement contains customary covenants and provisions, including covenants of Intermountain not to permit, as of the end of any fiscal quarter, the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent. Other covenants include limitations on the sale of certain assets and on the making of certain loans and investments.

Intermountain's credit agreement contains cross-default provisions. These provisions state that if (i) Intermountain fails to make any payment with respect to any indebtedness or guarantee in excess of a specified amount, (ii) any other event occurs that would permit the holders of indebtedness or the beneficiaries of guarantees to become payable, or (iii) certain conditions result in an early termination date under any swap contract that is in excess of $10 million, then Intermountain shall be in default under the revolving credit agreement.

MDU Energy Capital, LLC The ability to request additional borrowings under the master shelf agreement expired in 2010; however, there is debt outstanding that is reflected in the following table. The master shelf agreement contains customary covenants and provisions, including covenants of MDU Energy Capital not to permit (A) the ratio of its total debt (on a consolidated basis) to adjusted total capitalization to be greater than 70 percent, or (B) the ratio of subsidiary debt to subsidiary capitalization to be greater than 65 percent, or (C) the ratio of Intermountain's total debt (determined on a consolidated basis) to total capitalization to be greater than 65 percent. The agreement also includes a covenant requiring the ratio of MDU Energy Capital earnings before interest and taxes to interest expense (on a consolidated basis), for the 12-month period ended each fiscal quarter, to be greater than 1.5 to 1. In addition, payment obligations under the master shelf agreement may be accelerated upon the occurrence of an event of default (as described in the agreement).

Centennial Energy Holdings, Inc. The ability to request additional borrowings under an uncommitted long-term master shelf agreement expired; however, there is debt outstanding that is reflected in the following table. The uncommitted long-term master shelf agreement contains customary covenants and provisions, including a covenant of Centennial and certain of its subsidiaries, not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 60 percent. The master shelf agreement also includes a covenant that does not permit the ratio of Centennial's earnings before interest, taxes, depreciation and amortization to interest expense, for the 12-month period ended each fiscal quarter, to be less than 1.75 to 1. Other covenants include minimum consolidated net worth, limitation on priority debt and restrictions on the sale of certain assets and on the making of certain loans and investments.

Williston Basin Interstate Pipeline Company The ability to request additional borrowings under the uncommitted long-term private shelf agreement expired December 23, 2011; however, there is debt outstanding that is reflected in the following table. The uncommitted long-term private shelf agreement contains customary covenants and provisions, including a covenant of Williston Basin not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 55 percent. Other covenants include limitation on priority debt and some restrictions on the sale of certain assets and the making of certain investments.

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

	2011	2010
	(In thousands)	
Senior Notes at a weighted average rate of 6.01%, due on dates ranging from May 15, 2012 to March 8, 2037	$ **1,287,576**	$ 1,358,848
Medium-Term Notes at a weighted average rate of 7.72%, due on dates ranging from September 4, 2012 to March 16, 2029	**81,000**	81,000
Other notes at a weighted average rate of 5.24%, due on dates ranging from September 1, 2020 to February 1, 2035	**40,469**	41,189
Credit agreements at a weighted average rate of 2.98%, due on dates ranging from September 30, 2012 to November 30, 2038	**15,633**	25,715
Total long-term debt	**1,424,678**	1,506,752
Less current maturities	**139,267**	72,797
Net long-term debt	$ **1,285,411**	$ 1,433,955

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2011, aggregate $139.3 million in 2012; $267.3 million in 2013; $9.3 million in 2014; $266.4 million in 2015; $288.4 million in 2016 and $454.0 million thereafter.

Note 10 - Asset Retirement Obligations

The Company records obligations related to the plugging and abandonment of natural gas and oil wells, decommissioning of certain electric generating facilities, reclamation of certain aggregate properties, special handling and disposal of hazardous materials at certain electric generating facilities, natural gas distribution facilities and buildings, and certain other obligations.

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

		2011		2010
		(In thousands)		
Balance at beginning of year	$	**95,970**	$	76,359
Liabilities incurred		**3,870**		8,608
Liabilities acquired		**—**		5,272
Liabilities settled		**(10,418)**		(10,740)
Accretion expense		**4,466**		3,588
Revisions in estimates		**3,921**		12,621
Other		**342**		262
Balance at end of year	$	**98,151**	$	95,970

The Company believes that any expenses related to asset retirement obligations at the Company's regulated operations will be recovered in rates over time and, accordingly, defers such expenses as regulatory assets.

The fair value of assets that are legally restricted for purposes of settling asset retirement obligations at December 31, 2011 and 2010, was $5.7 million and $5.7 million, respectively.

Note 11 - Preferred Stocks

Preferred stocks at December 31 were as follows:

		2011		2010
		(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

For the years 2011, 2010 and 2009, dividends declared on the 4.50% Series and 4.70% Series preferred stocks were $4.50 and $4.70 per share, respectively. 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 12 - Common Stock

The Stock Purchase Plan provides interested investors the opportunity to make optional cash investments and to reinvest all or a percentage of their cash dividends in shares of the Company's common stock. The K-Plan is partially funded with the Company's common stock. From January 2009 through December 2011, purchases of shares of common stock on the open market were used to fund the Stock Purchase Plan and K-Plan. At December 31, 2011, there were 23.2 million shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan.

The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. The declaration and payment of dividends is at the sole discretion of the board of directors, subject to limitations imposed by the Company's credit agreements, federal and state laws, and applicable regulatory limitations. In addition, the Company and Centennial are generally restricted to paying dividends out of capital accounts or net assets. The most restrictive limitations are discussed below.

Pursuant to a covenant under a credit agreement, Centennial may only make distributions to the Company in an amount up to 100 percent of Centennial's consolidated net income after taxes for the immediately preceding fiscal year. Intermountain and Cascade have regulatory limitations on the amount of dividends each can pay. Based on these limitations, approximately $2.2 billion of the net assets of the Company's subsidiaries were restricted from being used to transfer funds to the Company at December 31, 2011. In addition, the Company's credit agreement also contains restrictions on dividend payments. The most restrictive limitation requires the Company not to permit the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Based on this limitation, approximately $136 million of the Company's (excluding its subsidiaries) net assets would be restricted from use for dividend payments at December 31, 2011. In addition, state regulatory commissions may require the Company to maintain certain capitalization ratios. These requirements are not expected to affect the Company's ability to pay dividends in the near term.

Note 13 - Stock-Based Compensation

The Company has several stock-based compensation plans under which it is currently authorized to grant restricted stock and stock. As of December 31, 2011, there are 6.3 million remaining shares available to grant under these plans. The Company generally issues new shares of common stock to satisfy restricted stock, stock and performance share awards.

Total stock-based compensation expense was $3.5 million, net of income taxes of $2.2 million in 2011; $3.4 million, net of income taxes of $2.1 million in 2010; and $3.4 million, net of income taxes of $2.2 million in 2009.

As of December 31, 2011, total remaining unrecognized compensation expense related to stock-based compensation was approximately $5.5 million (before income taxes) which will be amortized over a weighted average period of 1.6 years.

Stock options

The Company had granted stock options to directors, key employees and employees. The Company has not granted stock options since 2003. Options granted to key employees automatically vested after nine years, but the plan provided for accelerated vesting based on the attainment of certain performance goals or upon a change in control of the Company, and expired ten years after the date of grant. Options granted to employees vested three years after the date of grant and expired ten years after the date of grant. Options granted to directors vested at the date of grant and expire ten years after the date of grant.

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

A summary of the status of the stock option plans at December 31, 2011, and changes during the year then ended was as follows:

	Number of Shares	Weighted Average Exercise Price
Balance at beginning of year	440,984	$ 13.34
Forfeited	(3,893)	13.22
Exercised	(430,341)	13.34
Balance at end of year	6,750	13.03
Exercisable at end of year	6,750	$ 13.03

Stock options outstanding as of December 31, 2011, had an aggregate intrinsic value of $57,000, and approximately six months of remaining contractual life. The aggregate intrinsic value represents the total intrinsic value (before income taxes), based on the Company's stock price on December 31, 2011, which would have been received by the option holders had all option holders exercised their options as of that date.

The Company received cash of $5.7 million, $5.0 million and $2.1 million from the exercise of stock options for the years ended December 31, 2011, 2010 and 2009, respectively. The aggregate intrinsic value of options exercised during the years ended December 31, 2011, 2010 and 2009, was $3.3 million, $2.6 million and $1.3 million, respectively.

Stock awards

Nonemployee directors may receive shares of common stock instead of cash in payment for directors' fees under the nonemployee director stock compensation plan. There were 55,141 shares with a fair value of $1.1 million, 43,128 shares with a fair value of $849,000 and 49,649 shares with a fair value of $879,000 issued under this plan during the years ended December 31, 2011, 2010 and 2009, respectively.

Performance share awards

Since 2003, key employees of the Company have been awarded performance share awards each year. Entitlement to performance shares is based on the Company's total shareholder return over designated performance periods as measured against a selected peer group.

Target grants of performance shares outstanding at December 31, 2011, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2009	2009-2011	257,836
March 2010	2010-2012	227,009
February 2011	2011-2013	277,309

Participants may earn from zero to 200 percent of the target grant of shares based on the Company's total shareholder return relative to that of the selected peer group. Compensation expense is based on the grant-date fair value as determined by Monte Carlo simulation. The blended volatility term structure ranges are comprised of 50 percent historical volatility and 50 percent implied volatility. Risk-free interest rates were based on U.S. Treasury security rates in effect as of the grant date. Assumptions used for grants of performance shares issued in 2011, 2010 and 2009 were:

	2011	2010	2009
Grant-date fair value	**$ 19.99**	$ 17.40	$ 20.39
Blended volatility range	**23.20% - 32.18%**	25.69% - 35.36%	40.40% - 50.98%
Risk-free interest rate range	**.09% - 1.34%**	.13% - 1.45%	.30% - 1.36%
Discounted dividends per share	**$ 1.23**	$ 1.04	$ 1.79

There were no performance shares that vested in 2011. The fair value of performance share awards that vested during the years ended December 31, 2010 and 2009, was $3.5 million and $2.8 million, respectively.

A summary of the status of the performance share awards for the year ended December 31, 2011, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	669,685	$ 22.19
Granted	278,252	19.99
Vested	—	—
Forfeited	(185,783)	30.55
Nonvested at end of period	762,154	$ 19.35

Note 14 - Income Taxes

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

	2011	2010	2009
		(In thousands)	
United States	**$ 333,486**	$ 336,450	$ (227,021)
Foreign	**2,740**	30,100	7,655
Income (loss) before income taxes from continuing operations	**$ 336,226**	$ 366,550	$ (219,366)

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

	2011	2010	2009
		(In thousands)	
Current:			
Federal	$ (7,188)	$ 37,014	$ 64,389
State	778	10,589	8,284
Foreign	127	4,451	254
	(6,283)	52,054	72,927
Deferred:			
Income taxes -			
Federal	105,528	62,618	(147,607)
State	13,157	4,147	(22,370)
Investment tax credit - net	240	(180)	213
	118,925	66,585	(169,764)
Change in uncertain tax benefits	(1,048)	3,230	562
Change in accrued interest	(1,320)	661	183
Total income tax expense (benefit)	$ 110,274	$ 122,530	$ (96,092)

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

	2011	2010
	(In thousands)	
Deferred tax assets:		
Regulatory matters	$ 119,189	$ 114,427
Accrued pension costs	95,260	82,085
Asset retirement obligations	26,380	24,391
Legal and environmental contingencies	21,788	13,622
Compensation-related	16,241	17,261
Other	41,055	40,307
Total deferred tax assets	319,913	292,093
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	715,482	679,809
Basis differences on natural gas and oil producing properties	210,146	152,455
Regulatory matters	84,963	64,017
Intangible asset amortization	14,307	14,843
Other	23,774	20,348
Total deferred tax liabilities	1,048,672	931,472
Net deferred income tax liability	$ (728,759)	$ (639,379)

As of December 31, 2011 and 2010, no valuation allowance has been recorded associated with the previously identified deferred tax assets.

The following table reconciles the change in the net deferred income tax liability from December 31, 2010, to December 31, 2011, to deferred income tax expense:

		2011
		(In thousands)
Change in net deferred income tax liability from the preceding table	$	89,380
Deferred taxes associated with other comprehensive loss		9,678
Deferred taxes associated with discontinued operations		8,090
Other		11,777
Deferred income tax expense for the period	$	118,925

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

Years ended December 31,	2011		2010		2009	
	Amount	%	Amount	%	Amount	%
			(Dollars in thousands)			
Computed tax at federal statutory rate	$ 117,679	35.0	$ 128,293	35.0	$ (76,778)	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax benefit (expense)	10,653	3.2	10,210	2.8	(7,280)	3.3
Resolution of tax matters and uncertain tax positions	(3,906)	(1.2)	667	.2	881	(.4)
Federal renewable energy credit	(3,485)	(1.0)	(2,185)	(.6)	(1,452)	.7
Depletion allowance	(3,266)	(1.0)	(2,810)	(.8)	(2,320)	1.0
Deductible K-Plan dividends	(2,282)	(.7)	(2,309)	(.6)	(2,369)	1.1
Foreign operations	(391)	(.1)	(588)	(.2)	(1,148)	.5
Domestic production activities deduction	—	—	—	—	(856)	.4
Other	(4,728)	(1.4)	(8,748)	(2.4)	(4,770)	2.2
Total income tax expense (benefit)	$ 110,274	32.8	$ 122,530	33.4	$ (96,092)	43.8

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

Deferred income taxes have been accrued with respect to temporary differences related to the Company's foreign operations. The amount of cumulative undistributed earnings for which there are temporary differences is approximately $6.9 million at December 31, 2011. The amount of deferred tax liability, net of allowable foreign tax credits, associated with the undistributed earnings at December 31, 2011, was approximately $1.6 million.

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

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

	2011	2010	2009
		(In thousands)	
Balance at beginning of year	$ 9,378	$ 6,148	$ 5,586
Additions for tax positions of prior years	4,172	3,230	562
Settlements	(2,344)	—	—
Balance at end of year	$ 11,206	$ 9,378	$ 6,148

Included in the balance of unrecognized tax benefits at December 31, 2011 and 2010, were $6.6 million and $3.8 million, respectively, of tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate was $6.0 million, including approximately $1.4 million for the payment of interest and penalties at December 31, 2011, and was $7.1 million, including approximately $1.5 million for the payment of interest and penalties at December 31, 2010.

It is likely that substantially all of the unrecognized tax benefits, as well as interest, at December 31, 2011, will be settled in the next twelve months due to the anticipated settlement of federal and state audits.

For the years ended December 31, 2011, 2010 and 2009, the Company recognized approximately $780,000, $2.0 million and $190,000, respectively, in interest expense. Penalties were not material in 2011, 2010 and 2009. The Company recognized interest income of approximately $1.9 million, $20,000 and $165,000 for the years ended December 31, 2011, 2010 and 2009, respectively. The Company had accrued liabilities of approximately $970,000 and $2.3 million at December 31, 2011 and 2010, respectively, for the payment of interest.

Note 15 - Business Segment Data

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

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 Idaho, Minnesota, Oregon and Washington. These operations also supply related value-added services.

The pipeline and energy services segment provides natural gas transportation, underground storage and gathering services through regulated and nonregulated pipeline systems primarily in the Rocky Mountain and northern Great Plains regions of the United States. This segment also provides cathodic protection and other energy-related services.

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

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

The construction services segment specializes in constructing and maintaining electric and communication lines, gas pipelines, fire suppression systems, and external lighting and traffic signalization equipment. This segment also provides utility excavation services and inside electrical wiring, cabling and mechanical services, sells and distributes electrical materials, and manufactures and distributes specialty equipment.

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

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:

	2011	2010	2009
		(In thousands)	
External operating revenues:			
Electric	$ **225,468**	$ 211,544	$ 196,171
Natural gas distribution	**907,400**	892,708	1,072,776
Pipeline and energy services	**210,846**	254,776	235,322
	1,343,714	1,359,028	1,504,269
Exploration and production	**359,873**	318,570	338,425
Construction materials and contracting	**1,509,538**	1,445,148	1,515,122
Construction services	**834,918**	786,802	818,685
Other	**2,449**	147	—
	2,706,778	2,550,667	2,672,232
Total external operating revenues	$ **4,050,492**	$ 3,909,695	$ 4,176,501
Intersegment operating revenues:			
Electric	$ **—**	$ —	$ —
Natural gas distribution	**—**	—	—
Pipeline and energy services	**67,497**	75,033	72,505
Exploration and production	**93,713**	115,784	101,230
Construction materials and contracting	**472**	—	—
Construction services	**19,471**	2,298	379
Other	**8,997**	7,580	9,487
Intersegment eliminations	**(190,150)**	(200,695)	(183,601)
Total intersegment operating revenues	$ **—**	$ —	$ —
Depreciation, depletion and amortization:			
Electric	$ **32,177**	$ 27,274	$ 24,637
Natural gas distribution	**44,641**	43,044	42,723
Pipeline and energy services	**25,502**	26,001	25,581
Exploration and production	**142,645**	130,455	129,922
Construction materials and contracting	**85,459**	88,331	93,615
Construction services	**11,399**	12,147	12,760
Other	**1,572**	1,591	1,304
Total depreciation, depletion and amortization	$ **343,395**	$ 328,843	$ 330,542

	2011	2010	2009
		(In thousands)	
Interest expense:			
Electric	$ **13,745**	$ 12,216	$ 9,577
Natural gas distribution	**29,444**	28,996	30,656
Pipeline and energy services	**10,516**	9,064	8,896
Exploration and production	**7,445**	8,580	10,621
Construction materials and contracting	**16,241**	19,859	20,495
Construction services	**4,473**	4,411	4,490
Other	**—**	47	43
Intersegment eliminations	**(510)**	(162)	(679)
Total interest expense	$ **81,354**	$ 83,011	$ 84,099
Income taxes:			
Electric	$ **7,242**	$ 11,187	$ 8,205
Natural gas distribution	**16,931**	12,171	16,331
Pipeline and energy services	**12,912**	13,933	22,982
Exploration and production	**46,298**	49,034	(187,000)
Construction materials and contracting	**11,227**	13,822	25,940
Construction services	**13,426**	11,456	15,189
Other	**2,238**	10,927	2,261
Total income taxes	$ **110,274**	$ 122,530	$ (96,092)
Earnings (loss) on common stock:			
Electric	$ **29,258**	$ 28,908	$ 24,099
Natural gas distribution	**38,398**	36,944	30,796
Pipeline and energy services	**23,082**	23,208	37,845
Exploration and production	**80,282**	85,638	(296,730)
Construction materials and contracting	**26,430**	29,609	47,085
Construction services	**21,627**	17,982	25,589
Other	**6,190**	21,046	7,357
Earnings (loss) on common stock before loss from discontinued operations	**225,267**	243,335	(123,959)
Loss from discontinued operations, net of tax*	**(12,926)**	(3,361)	—
Total earnings (loss) on common stock	$ **212,341**	$ 239,974	$ (123,959)
Capital expenditures:			
Electric	$ **52,072**	$ 85,787	$ 115,240
Natural gas distribution	**70,624**	75,365	43,820
Pipeline and energy services	**45,556**	14,255	70,168
Exploration and production	**272,855**	355,845	183,140
Construction materials and contracting	**52,303**	25,724	26,313
Construction services	**9,711**	14,849	12,814
Other	**18,759**	2,182	3,196
Net proceeds from sale or disposition of property and other	**(40,857)**	(78,761)	(26,679)
Total net capital expenditures	$ **481,023**	$ 495,246	$ 428,012

		2011		2010		2009
				(In thousands)		
Assets:						
Electric**	$	**672,940**	$	643,636	$	569,666
Natural gas distribution**		**1,679,091**		1,632,012		1,588,144
Pipeline and energy services		**526,797**		523,075		538,230
Exploration and production		**1,481,556**		1,342,808		1,137,628
Construction materials and contracting		**1,374,026**		1,382,836		1,449,469
Construction services		**418,519**		387,627		328,895
Other***		**403,196**		391,555		378,920
Total assets	$	**6,556,125**	$	6,303,549	$	5,990,952
Property, plant and equipment:						
Electric**	$	**1,068,524**	$	1,027,034	$	941,791
Natural gas distribution**		**1,568,866**		1,508,845		1,456,208
Pipeline and energy services		**719,291**		683,807		675,199
Exploration and production		**2,615,146**		2,356,938		2,028,794
Construction materials and contracting		**1,499,852**		1,486,375		1,514,989
Construction services		**124,796**		122,940		116,236
Other		**49,747**		32,564		33,365
Less accumulated depreciation, depletion and amortization		**3,361,208**		3,103,323		2,872,465
Net property, plant and equipment	$	**4,285,014**	$	4,115,180	$	3,894,117

* *Reflected in the Other category.*

** *Includes allocations of common utility property.*

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

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

Excluding the natural gas gathering arbitration charge of $16.5 million (after tax) in 2010, as discussed in Note 19, earnings from electric, natural gas distribution and pipeline and energy services are substantially all from regulated operations. Earnings from exploration and production, construction materials and contracting, construction services and other are all from nonregulated operations.

Capital expenditures for 2011, 2010 and 2009 include noncash transactions, including the issuance of the Company's equity securities, in connection with acquisitions. The net noncash transactions were $24.0 million in 2011, $17.5 million in 2010 and immaterial in 2009.

Note 16 - Employee Benefit Plans

Pension and other postretirement benefit plans

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

Defined pension plan benefits to all nonunion and certain union employees hired after December 31, 2005, were discontinued. Employees that would have been eligible for defined pension plan benefits are eligible to receive additional defined contribution plan benefits. Effective January 1, 2010, all benefit and service accruals for nonunion and certain union plans were frozen. Effective June 30, 2011, all benefit and service accruals for an additional union plan were frozen. These employees will be eligible to receive additional defined contribution plan benefits.

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

Changes in benefit obligation and plan assets for the years ended December 31, 2011 and 2010, and amounts recognized in the Consolidated Balance Sheets at December 31, 2011 and 2010, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2011	2010	**2011**	2010
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$ **388,589**	$ 352,915	$ **91,286**	$ 88,151
Service cost	**2,252**	2,889	**1,443**	1,357
Interest cost	**19,500**	19,761	**4,700**	4,817
Plan participants' contributions	**—**	—	**2,644**	2,500
Amendments	**—**	353	**—**	121
Actuarial loss	**62,722**	34,687	**17,940**	3,228
Curtailment gain	**(13,939)**	—	**—**	—
Benefits paid	**(23,506)**	(22,016)	**(7,324)**	(8,888)
Benefit obligation at end of year	**435,618**	388,589	**110,689**	91,286
Change in net plan assets:				
Fair value of plan assets at beginning of year	**277,598**	255,327	**70,610**	66,984
Actual gain (loss) on plan assets	**(4,718)**	37,853	**(872)**	7,278
Employer contribution	**28,626**	6,434	**3,027**	2,736
Plan participants' contributions	**—**	—	**2,644**	2,500
Benefits paid	**(23,506)**	(22,016)	**(7,324)**	(8,888)
Fair value of net plan assets at end of year	**278,000**	277,598	**68,085**	70,610
Funded status - under	$ **(157,618)**	$ (110,991)	$ **(42,604)**	$ (20,676)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other accrued liabilities (current)	$ **—**	$ —	$ **(550)**	$ (525)
Other liabilities (noncurrent)	**(157,618)**	(110,991)	**(42,054)**	(20,151)
Net amount recognized	$ **(157,618)**	$ (110,991)	$ **(42,604)**	$ (20,676)
Amounts recognized in accumulated other comprehensive (income) loss consist of:				
Actuarial loss	$ **189,494**	$ 117,840	$ **43,861**	$ 20,751
Prior service cost (credit)	**(632)**	631	**(8,615)**	(11,292)
Transition obligation	**—**	—	**2,128**	4,253
Total	$ **188,862**	$ 118,471	$ **37,374**	$ 13,712

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

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

The accumulated benefit obligation for the defined benefit pension plans reflected previously was $435.6 million and $374.5 million at December 31, 2011 and 2010, respectively.

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

	2011	2010
	(In thousands)	
Projected benefit obligation	$ 435,618	$ 388,589
Accumulated benefit obligation	$ 435,618	$ 374,538
Fair value of plan assets	$ 278,000	$ 277,598

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

	Pension Benefits			Other Postretirement Benefits		
	2011	2010	2009	**2011**	2010	2009
			(In thousands)			
Components of net periodic benefit cost:						
Service cost	$ **2,252**	$ 2,889	$ 8,127	$ **1,443**	$ 1,357	$ 2,206
Interest cost	**19,500**	19,761	21,919	**4,700**	4,817	5,465
Expected return on assets	**(22,809)**	(23,643)	(25,062)	**(5,051)**	(5,512)	(5,471)
Amortization of prior service cost (credit)	**45**	152	605	**(2,677)**	(3,303)	(2,756)
Recognized net actuarial loss	**4,656**	2,622	2,096	**753**	845	970
Curtailment loss	**1,218**	—	1,650	—	—	—
Amortization of net transition obligation	—	—	—	**2,125**	2,125	2,125
Net periodic benefit cost, including amount capitalized	**4,862**	1,781	9,335	**1,293**	329	2,539
Less amount capitalized	**1,196**	791	1,127	**(50)**	(92)	330
Net periodic benefit cost	**3,666**	990	8,208	**1,343**	421	2,209
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss:						
Net (gain) loss	**76,310**	20,477	(29,000)	**23,863**	1,462	(2,314)
Prior service cost (credit)	—	353	—	—	121	(9,321)
Amortization of actuarial loss	**(4,656)**	(2,622)	(2,096)	**(753)**	(845)	(970)
Amortization of prior service (cost) credit	**(1,263)**	(152)	(2,255)	**2,677**	3,303	2,756
Amortization of net transition obligation	—	—	—	**(2,125)**	(2,125)	(2,125)
Total recognized in accumulated other comprehensive (income) loss	**70,391**	18,056	(33,351)	**23,662**	1,916	(11,974)
Total recognized in net periodic benefit cost and accumulated other comprehensive (income) loss	$ **74,057**	$ 19,046	$ (25,143)	$ **25,005**	$ 2,337	$ (9,765)

The estimated net loss and prior service credit for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2012 are $7.6 million and $85,000, respectively. The estimated net loss, prior service credit and transition obligation for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2012 are $1.9 million, $1.1 million and $2.1 million, respectively.

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

	Pension Benefits		Other Postretirement Benefits	
	2011	2010	**2011**	2010
Discount rate	**4.16%**	5.26%	**4.13%**	5.21%
Expected return on plan assets	**7.75%**	7.75%	**6.75%**	6.75%
Rate of compensation increase	**N/A**	4.00%	**4.00%**	4.00%

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

	Pension Benefits		Other Postretirement Benefits	
	2011	2010	**2011**	2010
Discount rate	**5.26 %**	5.75%	**5.21%**	5.75%
Expected return on plan assets	**7.75 %**	8.25%	**6.75%**	7.25%
Rate of compensation increase	**4.00% / N/A** *	4.00%	**4.00%**	4.00%

* *Effective June 30, 2011, all benefit and service accruals for a union plan were frozen. Compensation increases had previously been frozen for all other plans.*

The expected rate of return on pension plan assets is based on the targeted asset allocation range of 60 percent to 70 percent equity securities and 30 percent to 40 percent fixed-income securities and the expected rate of return from these asset categories. The expected rate of return on other postretirement plan assets is based on the targeted asset allocation range of 65 percent to 75 percent equity securities and 25 percent to 35 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:

	2011	2010
Health care trend rate assumed for next year	**6.0% - 8.0%**	6.0% - 8.5%
Health care cost trend rate - ultimate	**5.0% - 6.0%**	5.0% - 6.0%
Year in which ultimate trend rate achieved	**1999 - 2017**	1999 - 2017

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

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates would have had the following effects at December 31, 2011:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 171	$ (822)
Effect on postretirement benefit obligation	$ 3,175	$ (10,946)

The Company's pension assets are managed by 12 outside investment managers. The Company's other postretirement assets are managed by one outside investment manager. The Company's investment policy with respect to pension and other postretirement assets is to make 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 futures contracts, equity private placement, employer securities, leveraged or derivative securities, options, direct real estate investments, precious metals, venture capital and limited partnerships. The guidelines also prohibit short selling and margin transactions. The Company's practice is to periodically review and rebalance asset categories based on its targeted asset allocation percentage policy.

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

	Fair Value Measurements at December 31, 2011, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2011
	(In thousands)			
Assets:				
Cash equivalents	$ 2,256	$ 17,534	$ —	$ 19,790
Equity securities:				
U.S. companies	99,315	—	—	99,315
International companies	35,353	—	—	35,353
Collective and mutual funds (a)	43,214	15,541	—	58,755
Corporate bonds	—	23,579	289	23,868
Mortgage-backed securities	—	22,987	—	22,987
Municipal bonds	—	9,290	—	9,290
U.S. Treasury securities	—	8,642	—	8,642
Total assets measured at fair value	$ 180,138	$ 97,573	$ 289	$ 278,000

(a) Collective and mutual funds invest approximately 26 percent in common stock of mid-cap U.S. companies, 26 percent in common stock of large-cap U.S. companies, 13 percent in U.S. Treasuries, 6 percent in corporate bonds and 29 percent in other investments.

	Fair Value Measurements at December 31, 2010, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2010
	(In thousands)			
Assets:				
Cash equivalents	$ 4,663	$ 8,699	$ —	$ 13,362
Equity securities:				
U.S. companies	102,944	—	—	102,944
International companies	40,017	—	—	40,017
Collective and mutual funds (a)	45,410	17,701	—	63,111
Collateral held on loaned securities (b)	—	23,148	694	23,842
Corporate bonds	—	23,014	—	23,014
Mortgage-backed securities	—	19,478	—	19,478
U.S. Treasury securities	—	9,239	—	9,239
Municipal bonds	—	8,285	—	8,285
Total assets measured at fair value	193,034	109,564	694	303,292
Liabilities:				
Obligation for collateral received	25,694	—	—	25,694
Net assets measured at fair value	$ 167,340	$ 109,564	$ 694	$ 277,598

(a) Collective and mutual funds invest approximately 28 percent in common stock of mid-cap U.S. companies, 24 percent in common stock of large-cap U.S. companies, 13 percent in U.S. Treasuries, 11 percent in mortgage-backed securities, 10 percent in corporate bonds, 8 percent in foreign fixed-income investments and 6 percent in common stock of small-cap U.S. companies.

(b) This class includes collateral held at December 31, 2010, as a result of participation in a securities lending program. Cash collateral is invested by the trustee primarily in repurchase agreements, mutual funds and commercial paper.

The following table sets forth a summary of changes in the fair value of the pension plan's Level 3 assets for the year ended December 31, 2011:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
	Corporate Bonds	Collateral Held on Loaned Securities	Total
	(In thousands)		
Balance at beginning of year	$ —	$ 694	$ 694
Total realized/unrealized losses	(2)	(259)	(261)
Purchases, issuances and settlements (net)	291	(435)	(144)
Balance at end of year	$ 289	$ —	$ 289

The following table sets forth a summary of changes in the fair value of the pension plan's Level 3 assets for the year ended December 31, 2010:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)
	Collateral Held on Loaned Securities
	(In thousands)
Balance at beginning of year	$ 937
Total realized/unrealized losses	189
Purchases, issuances and settlements (net)	(432)
Balance at end of year	$ 694

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

	Fair Value Measurements at December 31, 2011, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2011
		(In thousands)		
Assets:				
Cash equivalents	$ 59	$ 1,836	$ —	$ 1,895
Equity securities:				
U.S. companies	2,098	—	—	2,098
International companies	262	—	—	262
Insurance investment contract*	—	63,830	—	63,830
Total assets measured at fair value	$ 2,419	$ 65,666	$ —	$ 68,085

* The insurance investment contract invests approximately 49 percent in common stock of large-cap U.S. companies, 15 percent in U.S. Treasuries, 12 percent in mortgage-backed securities, 11 percent in corporate bonds, and 13 percent in other investments.

	Fair Value Measurements at December 31, 2010, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2010
		(In thousands)		
Assets:				
Cash equivalents	$ 53	$ 1,274	$ —	$ 1,327
Equity securities:				
U.S. companies	2,791	—	—	2,791
International companies	353	—	—	353
Insurance investment contract*	—	66,139	—	66,139
Total assets measured at fair value	$ 3,197	$ 67,413	$ —	$ 70,610

* The insurance investment contract invests approximately 53 percent in common stock of large-cap U.S. companies, 21 percent in corporate bonds, 12 percent in mortgage-backed securities and 14 percent in other investments.

The Company expects to contribute approximately $20.2 million to its defined benefit pension plans and approximately $4.0 million to its postretirement benefit plans in 2012.

The following benefit payments, which reflect future service, as appropriate, and expected Medicare Part D subsidies are as follows:

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
	(In thousands)		
2012	$ 22,426	$ 6,892	$ 618
2013	22,811	7,062	656
2014	23,082	7,188	694
2015	23,508	7,298	730
2016	23,893	7,371	766
2017 - 2021	127,895	37,682	4,322

Nonqualified benefit plans

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified benefit plans for executive officers and certain key management employees that generally provide for defined benefit payments at age 65 following the employee's retirement or to their beneficiaries upon death for a 15-year period. The Company had investments of $76.9 million and $77.5 million at December 31, 2011 and 2010, respectively, consisting of equity securities of $38.4 million and $39.5 million, respectively, life insurance carried on plan participants (payable upon the employee's death) of $31.8 million and $30.7 million, respectively, and other investments of $6.7 million and $7.3 million, respectively. The Company anticipates using these investments to satisfy obligations under these plans. The Company's net periodic benefit cost for these plans was $8.1 million, $7.8 million and $8.8 million in 2011, 2010 and 2009, respectively. The total projected benefit obligation for these plans was $113.8 million and $99.4 million at December 31, 2011 and 2010, respectively. The accumulated benefit obligation for these plans was $105.7 million and $93.2 million at December 31, 2011 and 2010, respectively. A weighted average discount rate of 4.00 percent and 5.11 percent at December 31, 2011 and 2010, respectively, and a rate of compensation increase of 4.00 percent at December 31, 2011 and 2010, were used to determine benefit obligations. A discount rate of 5.11 percent and 5.75 percent at December 31, 2011 and 2010, respectively, and a rate of compensation increase of 4.00 percent at December 31, 2011 and 2010, were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans are expected to aggregate $5.2 million in 2012; $5.9 million in 2013; $5.8 million in 2014; $6.9 million in 2015; $6.8 million in 2016 and $38.3 million for the years 2017 through 2021.

Defined contribution plans

The Company sponsors various defined contribution plans for eligible employees. Costs incurred by the Company under these plans were $27.1 million in 2011, $24.4 million in 2010 and $20.5 million in 2009.

Multiemployer plans

The Company contributes to a number of multiemployer defined benefit pension plans under the terms of collective-bargaining agreements that cover its union-represented employees. The risks of participating in these multiemployer plans are different from single-employer plans in the following aspects:

- Assets contributed to the multiemployer plan by one employer may be used to provide benefits to employees of other participating employers
- If a participating employer stops contributing to the plan, the unfunded obligations of the plan may be borne by the remaining participating employers

- If the Company chooses to stop participating in some of its multiemployer plans, the Company may be required to pay those plans an amount based on the underfunded status of the plan, referred to as a withdrawal liability

The Company's participation in these plans for the annual period ended December 31, 2011, is outlined in the following table. Unless otherwise noted, the most recent Pension Protection Act zone status available in 2011 and 2010 is for the plan's year-end at December 31, 2010, and December 31, 2009, respectively. The zone status is based on information that the Company received from the plan and is certified by the plan's actuary. Among other factors, plans in the red zone are generally less than 65 percent funded, plans in the yellow zone are between 65 percent and 80 percent funded, and plans in the green zone are at least 80 percent funded. From 2009 to 2010 and 2010 to 2011, contributions by the Company to multiemployer defined benefit pension plans decreased as a result of a reduction in covered employees corresponding to a decline in overall business.

Pension Fund	EIN/Pension Plan Number	Pension Protection Act Zone Status 2011	Pension Protection Act Zone Status 2010	FIP/RP Status Pending/ Implemented	Contributions **2011**	Contributions 2010	Contributions 2009	Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
					(In thousands)				
Edison Pension Plan	93-6061681-001	Green	Green	No	$ **2,700**	$ 1,933	$ 1,627	No	12/31/2012
IBEW Local 38 Pension Plan	34-6574238-001	Yellow as of 4/30/2011	Yellow as of 4/30/2010	Implemented	**1,469**	1,277	594	No	*
IBEW Local No. 82 Pension Plan	31-6127268-001	Red as of 6/30/2011	Red as of 6/30/2010	Implemented	**1,331**	1,569	1,197	No	*
IBEW Local 648 Pension Plan	31-6134845-001	Red as of 2/28/2011	Red as of 2/28/2010	Implemented	**722**	781	641	No	8/31/2012
Laborers Pension Trust Fund for Northern California	94-6277608-001	Yellow as of 5/31/2011	Yellow as of 5/31/2010	Implemented	**628**	413	325	No	6/30/2012*
Local Union 212 IBEW Pension Trust Fund	31-6127280-001	Yellow as of 4/30/2011	Yellow as of 4/30/2010	Implemented	**776**	679	469	No	*
National Electrical Benefit Fund	53-0181657-001	Green	Green	No	**4,841**	4,826	5,462	No	5/31/2014*
OE Pension Trust Fund	94-6090764-001	Yellow	Yellow	Implemented	**1,367**	1,035	1,061	No	3/31/2016*
Other funds					**15,324**	17,763	21,103		
Total contributions					$ **29,158**	$ 30,276	$ 32,479		

* *Plan includes collective bargaining agreements which have expired. The agreements contain provisions that automatically renew the existing contracts in lieu of a new negotiated collective bargaining agreement.*

The Company was listed in the plans' Forms 5500 as providing more than 5 percent of the total contributions for the following plans and plan years:

Pension Fund	Year Contributions to Plan Exceeded More Than 5 Percent of Total Contributions (as of December 31 of the Plan's Year-End)
Defined Benefit Pension Plan of AGC-IUOE Local 701 Pension Trust Fund	2010 and 2009
Edison Pension Plan	2010 and 2009
Eighth District Electrical Pension Fund	2010 and 2009
IBEW Local 38 Pension Plan	2010 and 2009
IBEW Local No. 82 Pension Plan	2010 and 2009
IBEW Local Union No. 357 Pension Plan A	2010 and 2009
IBEW Local 648 Pension Plan	2010 and 2009
Idaho Plumbers and Pipefitters Pension Plan	2010 and 2009
Laborers AGC Pension Trust of Montana	2009
Local Union No. 124 IBEW Pension Trust Fund	2010 and 2009
Local Union 212 IBEW Pension Trust Fund	2010 and 2009
Minnesota Teamsters Constr Division Pension Fund	2010 and 2009
Operating Engineers Local 800 and Wyoming Contractors Association, Inc. Pension Plan for Wyoming	2010 and 2009
Plumbers & Pipefitters Local 162 Pension Fund	2010 and 2009
Southwest Marine Pension Trust	2009

The Company also contributes to a number of multiemployer other postretirement plans under the terms of collective-bargaining agreements that cover its union-represented employees. These plans provide benefits such as health insurance, disability insurance and life insurance to retired union employees. Many of the multiemployer other postretirement plans are combined with active multiemployer health and welfare plans. The Company's total contributions to its multiemployer other postretirement plans, which also includes contributions to active multiemployer health and welfare plans, were $24.0 million, $24.7 million and $28.9 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Amounts contributed in 2011, 2010 and 2009 to defined contribution multiemployer plans were $15.3 million, $15.4 million and $16.4 million, respectively.

Note 17 - Jointly Owned Facilities

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

The Company's share of the stations 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:

	2011	2010
	(In thousands)	
Big Stone Station:		
Utility plant in service	$ 63,715	$ 60,404
Less accumulated depreciation	42,475	41,136
	$ 21,240	$ 19,268
Coyote Station:		
Utility plant in service	$ 131,719	$ 131,395
Less accumulated depreciation	86,788	84,710
	$ 44,931	$ 46,685
Wygen III:*		
Utility plant in service	$ 63,300	$ 63,215
Less accumulated depreciation	2,106	838
	$ 61,194	$ 62,377

** Began commercial operation on April 1, 2010.*

Note 18 - Regulatory Matters and Revenues Subject to Refund

On May 20, 2011, Montana-Dakota filed an application with the NDPSC requesting advance determination of prudence that the addition of the air quality control system at the Big Stone Station, to comply with the Clean Air Act and the South Dakota Regional Haze Implementation Plan, is reasonable and prudent. A hearing was held on November 29, 2011. On January 9, 2012, Montana-Dakota, Otter Tail Corporation and the NDPSC Advocacy Staff filed a settlement agreement with the NDPSC that reflects agreement that the air quality control system is prudent. An order is expected in the first quarter of 2012.

On July 7, 2011, Montana-Dakota filed for an advance determination of prudence with the NDPSC on the construction of an 88-MW simple cycle natural gas turbine and associated facilities projected to be in service in 2015. The turbine will be located on company-owned property that is adjacent to Montana-Dakota's Heskett Generating Station near Mandan, North Dakota, and would be used to meet the capacity requirements of Montana-Dakota's integrated electric system service customers. The capacity will be a partial replacement for third party contract capacity expiring in 2015. Project cost is estimated to be $85.6 million. A hearing was held on January 10, 2012. On January 18, 2012, Montana-Dakota and the NDPSC Advocacy Staff filed a settlement agreement with the NDPSC that reflects agreement that the natural gas turbine is prudent and a certificate of need should be approved. An order is expected in the first quarter of 2012.

On November 15, 2011, the MNPUC issued a Notice of Investigation; Opportunity to Respond and Comment to investigate whether Great Plains' rates are unreasonable and whether Great Plains should be ordered to initiate a general rate proceeding as Great Plains has earned in excess of its authorized return and the excess earnings are likely to continue into the future. On December 2, 2011, Great Plains responded to the MNPUC's Notice. On January 30, 2012, the MNPUC issued an order that found that the reasonableness of Great Plains' rates had not been resolved to the MNPUC's satisfaction and requires Great Plains to initiate a rate proceeding within 180 days of the order. In addition, the MNPUC encouraged Great Plains, the Minnesota Department of Commerce and any other interested parties to enter into settlement discussions with the requirement that the interested parties file a report on the status of settlement discussions within 60 days of the order.

Note 19 - Commitments and Contingencies

The Company is party to claims and lawsuits arising out of its business and that of its consolidated subsidiaries. The Company accrues a liability for those contingencies when the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Company does not accrue liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is probable or reasonably possible and which are material, the Company discloses the nature of the contingency and, where feasible, an estimate of the possible loss. The Company had accrued liabilities of $64.1 million and $45.3 million for contingencies related to litigation and environmental matters as of December 31, 2011 and 2010, respectively, which includes amounts that may have been accrued for matters discussed in Litigation and Environmental matters within this note.

Litigation

Guarantee Obligation Under a Construction Contract Centennial guaranteed CEM's obligations under a construction contract with LPP for a 550-MW combined-cycle electric generating facility near Hobbs, New Mexico. Centennial Resources sold CEM in July 2007 to Bicent, which provided a $10 million bank letter of credit to Centennial in support of the guarantee obligation, which letter of credit expired in November 2010. In February 2009, Centennial received a Notice and Demand from LPP under the guarantee agreement alleging that CEM did not meet certain of its obligations under the construction contract and demanding that Centennial indemnify LPP against all losses, damages, claims, costs, charges and expenses arising from CEM's alleged failures. In December 2009, LPP submitted a demand for arbitration of its dispute with CEM to the American Arbitration Association. The demand sought compensatory damages of $149.7 million. In June 2010, CEM and Bicent made a demand on Centennial Resources for indemnification under the 2007 purchase and sale agreement for indemnifiable losses, including defense fees and costs arising from LPP's arbitration demand and related to Centennial Resources' ownership of CEM prior to its sale to Bicent. Centennial and Centennial Resources filed a complaint with the Supreme Court of the State of New York in November 2010, against Bicent seeking damages for breach of contract and other relief including specific performance of the 2007 purchase and sale agreement allowing for Centennial Resources' participation in the arbitration proceeding and replacement of the letter of credit. On September 19, 2011, Bicent filed a counterclaim seeking damages against Centennial Resources related to Bicent's costs of defending the LPP arbitration demand which Bicent alleged were in excess of $14.0 million. The arbitration hearing on LPP's claim was held in the third quarter of 2011, and an arbitration award was issued January 13, 2012, awarding LPP $22.0 million. Centennial subsequently received a demand from LPP for payment of the arbitration award plus interest and attorneys' fees. An accrual related to the guarantee as a result of the arbitration award is recorded in discontinued operations on the Consolidated Statement of Income. The Company intends to vigorously defend against the claims of LPP and Bicent.

Construction Materials In 2009, LTM provided pavement work under a subcontract for reconstruction at the Klamath Falls Airport owned by the City of Klamath Falls, Oregon. In October 2010, the City of Klamath Falls filed a complaint in Oregon Circuit Court against the project's general contractor alleging the work performed by LTM is defective. The general contractor tendered the defense and indemnity of the claim to LTM and its insurance carrier. On January 18, 2011, the general contractor served a third party complaint against LTM seeking indemnity and contribution for damages imposed on the general contractor. LTM filed a fourth-party complaint seeking contribution and indemnity for damages imposed on LTM against the project engineer firm which prepared the specifications for the airport runway. LTM's insurance carrier accepted defense of the complaint against the general contractor and the third party complaint against LTM subject to reservation of its rights under the applicable insurance policy. Damages, including removal and replacement of the paved runway, were estimated by the plaintiff in its complaint as $6.0 million to $11.0 million. The Oregon Circuit Court granted a motion by LTM to dismiss certain of the plaintiff's claims relating to approximately $5.0 million of damages but allowed the plaintiff to amend its complaint. In its amended complaint, the plaintiff asserted new claims with estimated damages of $21.9 million plus interest and attorney fees. LTM and its insurers have been engaged in mediation and settlement discussions with the other parties to resolve this matter.

Until the fall of 2011 when it discontinued active mining operations at the pit, JTL operated the Target Range Gravel Pit in Missoula County, Montana under a 1975 reclamation contract pursuant to the Montana Opencut Mining Act. In September 2009, the Montana DEQ sent a letter asserting JTL was in violation of the Montana Opencut Mining Act by conducting mining operations outside a permitted area. JTL filed a complaint in Montana First Judicial District Court in June 2010, seeking a declaratory order that the reclamation contract is a valid permit under the Montana Opencut Mining Act. The Montana DEQ filed an answer and counterclaim to the complaint in August 2011, alleging JTL was in violation of the Montana Opencut Mining Act and requesting imposition of penalties of not more than $3.7 million plus not more than $5,000 per day from the date of the counterclaim. The Company believes the operation of the Target Range Gravel Pit was conducted under a valid permit; however, the imposition of civil penalties is reasonably possible. The Company intends to resolve this matter through settlement or continuation of the Montana First Judicial District Court litigation.

Natural Gas Gathering Operations In January 2010, SourceGas filed an application with the Colorado State District Court to compel Bitter Creek to arbitrate a dispute regarding operating pressures under a natural gas gathering contract on one of Bitter Creek's pipeline gathering systems in Montana. Bitter Creek resisted the application and sought a declaratory order interpreting the gathering contract. In May 2010, the Colorado State District Court granted the application and ordered Bitter Creek into arbitration. An arbitration hearing was held in August 2010. In October 2010, Bitter Creek was notified that the arbitration panel issued an award in favor of SourceGas for approximately $26.6 million. As a result, Bitter Creek, which is included in the pipeline and energy services segment, recorded a $26.6 million charge ($16.5 million after tax) in the third quarter of 2010, which is recorded in operation and maintenance expense on the Consolidated Statement of Income. On April 20, 2011, the Colorado State District Court entered an order denying a motion by Bitter Creek to vacate the arbitration award and granting a motion by SourceGas to confirm the arbitration award as a court judgment. The Colorado State District Court also awarded $293,000 to SourceGas for legal fees and expenses. Bitter Creek filed an appeal from the Colorado State District Court's order and judgment to the Colorado Court of Appeals on April 28, 2011.

In a related matter, Omimex filed a complaint against Bitter Creek in Montana Seventeenth Judicial District Court in July 2010 alleging Bitter Creek breached a separate gathering contract with Omimex as a result of the increased operating pressures demanded by SourceGas on the same natural gas gathering system. In December 2011, Omimex filed an amended complaint alleging Bitter Creek breached obligations to operate its gathering system as a common carrier under United States and Montana law. Bitter Creek removed the action to the United States District Court for the District of Montana. Expert reports submitted by Omimex contend its damages as a result of the increased operating pressures are $18.8 million to $22.6 million. The Company believes the claims asserted by Omimex are without merit and intends to vigorously defend against the claims.

The Company also is involved in other legal actions in the ordinary course of its business. After taking into account liabilities accrued for the foregoing matters, management believes that the outcomes with respect to the above and other legal proceedings will not have a material effect upon the Company's financial position, results of operations or cash flows.

Environmental matters

Portland Harbor Site In December 2000, Knife River - Northwest was named by the EPA as a PRP in connection with the cleanup of a riverbed site adjacent to a commercial property site acquired by Knife River - Northwest from Georgia-Pacific West, Inc. in 1999. The riverbed site is part of the Portland, Oregon, Harbor Superfund Site. The EPA wants responsible parties to share in the cleanup of sediment contamination in the Willamette River. To date, costs of the overall remedial investigation and feasibility study of the harbor site are being recorded, and initially paid, through an administrative consent order by the LWG, a group of several entities, which does not include Knife River - Northwest or Georgia-Pacific West, Inc. Investigative costs are indicated to be in excess of $70 million. It is not possible to estimate the cost of a corrective action plan until the remedial investigation and feasibility study have been completed, the EPA has decided on a strategy and a ROD has been published. Corrective action will be taken after the development of a proposed plan and ROD on the harbor site is issued. Knife River - Northwest also received notice in January 2008 that the Portland Harbor Natural Resource Trustee Council intends to perform an injury assessment to natural resources resulting from the release of hazardous substances at the Harbor Superfund Site. The Portland Harbor Natural Resource Trustee Council indicates the injury determination is appropriate to facilitate early settlement of damages and restoration for natural resource injuries. It is not possible to estimate the costs of natural resource damages until an assessment is completed and allocations are undertaken.

Based upon a review of the Portland Harbor sediment contamination evaluation by the Oregon DEQ and other information available, Knife River - Northwest does not believe it is a Responsible Party. In addition, Knife River - Northwest has notified Georgia-Pacific West, Inc., that it intends to seek indemnity for liabilities incurred in relation to the above matters pursuant to the terms of their sale agreement. Knife River - Northwest has entered into an agreement tolling the statute of limitations in connection with the LWG's potential claim for contribution to the costs of the remedial investigation and feasibility study. By letter in March 2009, LWG stated its intent to file suit against Knife River - Northwest and others to recover LWG's investigation costs to the extent Knife River - Northwest cannot demonstrate its non-liability for the contamination or is unwilling to participate in an alternative dispute resolution process that has been established to address the matter. At this time, Knife River - Northwest has agreed to participate in the alternative dispute resolution process.

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

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

The first claim is for contamination at a site in Eugene, Oregon which was received in 1995. There are PRPs in addition to Cascade that may be liable for cleanup of the contamination. Some of these PRPs have shared in the investigation costs. It is expected that these and other PRPs will share in the cleanup costs. Several alternatives for cleanup have been identified, with preliminary cost estimates ranging from approximately $500,000 to $11.0 million. The Oregon DEQ is preparing a staff report which will recommend a cleanup alternative for the site. It is not known at this time what share of the cleanup costs will actually be borne by Cascade; however, Cascade anticipates its proportional share could be approximately 50 percent. Cascade has reserved $1.2 million for remediation of this site.

The second claim is for contamination at a site in Bremerton, Washington which was received in 1997. A preliminary investigation has found soil and groundwater at the site contain contaminants requiring further investigation and cleanup. EPA conducted a Targeted Brownfields Assessment of the site and released a report summarizing the results of that assessment in August 2009. The assessment confirms that contaminants have affected soil and groundwater at the site, as well as sediments in the adjacent Port Washington Narrows. Alternative remediation options have been identified with preliminary cost estimates ranging from $340,000 to $6.4 million. Data developed through the assessment and previous investigations indicates the contamination likely derived from multiple, different sources and multiple current and former owners of properties and businesses in the vicinity of the site may be responsible for the contamination. In April 2010, the Washington Department of Ecology issued notice it considered Cascade a PRP for hazardous substances at the site. In September 2011, the EPA issued notice of a proposal to add the site to the National Priorities List. Cascade has met with the EPA to discuss a possible settlement agreement and administrative order for performance of a remedial investigation and feasibility study of the site with the intent of reaching consensus on the scope and schedule for the remedial investigation and feasibility study. Cascade has reserved $6.4 million for remediation of this site. In April 2010, Cascade filed a petition with the WUTC for authority to defer the costs, which are included in other noncurrent assets, incurred in relation to the environmental remediation of this site until the next general rate case. The WUTC approved the petition in September 2010, subject to conditions set forth in the order.

The third claim is for contamination at a site in Bellingham, Washington. Cascade received notice from a party in May 2008 that Cascade may be a PRP, along with other parties, for contamination from a manufactured gas plant owned by Cascade and its predecessor from about 1946 to 1962. The notice indicates that current estimates to complete investigation and cleanup of the site exceed $8.0 million. Other PRPs have reached an agreed order and work plan with the Washington Department of Ecology for completion of a remedial investigation and feasibility study for the site. A report documenting the initial phase of the remedial investigation was completed in June 2011. There is currently not enough information available to estimate the potential liability to Cascade associated with this claim although Cascade believes its proportional share of any liability will be relatively small in comparison to other PRPs. The plant manufactured gas from coal between approximately 1890 and 1946. In 1946, shortly after Cascade's predecessor acquired the plant, it converted the plant to a propane-air gas facility. There are no documented wastes or by-products resulting from the mixing or distribution of propane-air gas.

Cascade has received notices from certain of its insurance carriers that they will participate in defense of Cascade for these contamination claims subject to full and complete reservations of rights and defenses to insurance coverage. To the extent these claims are not covered by insurance, Cascade will seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers.

Operating leases

The Company leases certain equipment, facilities and land under operating lease agreements. The amounts of annual minimum lease payments due under these leases as of December 31, 2011, were $27.8 million in 2012, $24.3 million in 2013, $16.4 million in 2014, $8.6 million in 2015, $5.8 million in 2016 and $35.9 million thereafter. Rent expense was $40.7 million, $38.7 million and $43.4 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Purchase commitments

The Company has entered into various commitments, largely natural gas and coal supply, purchased power, natural gas transportation and storage, service and construction materials supply contracts. These commitments range from one to 49 years. The commitments under these contracts as of December 31, 2011, were $478.0 million in 2012, $215.9 million in 2013, $135.8 million in 2014, $71.1 million in 2015, $36.7 million in 2016 and $287.0 million thereafter. These commitments were not reflected in the Company's consolidated financial statements. Amounts purchased under various commitments for the years ended December 31, 2011, 2010 and 2009, were $626.3 million, $611.7 million and $723.1 million.

Guarantees

Centennial guaranteed CEM's obligations under a construction contract. For further information, see Litigation in this note.

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

WBI Holdings has guaranteed certain of Fidelity's natural gas and oil swap and collar agreement obligations. There is no fixed maximum amount guaranteed in relation to the natural gas and oil 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 swap and collar agreements at December 31, 2011, expire in the years ranging from 2012 to 2013; 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 $4.3 million and was reflected on the Consolidated Balance Sheet at December 31, 2011. In the event Fidelity defaults under its obligations, WBI Holdings would be required to make payments under its guarantees.

Certain subsidiaries of the Company have outstanding guarantees to third parties that guarantee the performance of other subsidiaries of the Company. These guarantees are related to construction contracts, natural gas transportation and sales agreements, gathering contracts and certain other guarantees. At December 31, 2011, the fixed maximum amounts guaranteed under these agreements aggregated $85.6 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $42.0 million in 2012; $34.4 million in 2013; $1.3 million in 2014; $100,000 in 2015; $100,000 in 2016; $800,000 in 2018; $300,000 in 2019; $2.6 million, which is subject to expiration on a specified number of days after the receipt of written notice; and $4.0 million, which has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above guarantees was $500,000 and was reflected on the Consolidated Balance Sheet at December 31, 2011. In the event of default under these guarantee obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee.

Certain subsidiaries have outstanding letters of credit to third parties related to insurance policies, natural gas transportation agreements and other agreements, some of which are guaranteed by other subsidiaries of the Company. At December 31, 2011, the fixed maximum amounts guaranteed under these letters of credit, aggregated $27.4 million. In 2012 and 2013, $24.1 million and $3.3 million, respectively, of letters of credit are scheduled to expire. There were no amounts outstanding under the above letters of credit at December 31, 2011.

WBI Holdings has an outstanding guarantee to Williston Basin. This guarantee is related to a natural gas transportation and storage agreement that guarantees the performance of Prairielands. At December 31, 2011, the fixed maximum amount guaranteed under this agreement was $5.0 million and is scheduled to expire in 2014. In the event of Prairielands' default in its payment obligations, WBI Holdings would be required to make payment under its guarantee. The amount outstanding by Prairielands under the above guarantee was $1.2 million. The amount outstanding under this guarantee was not reflected on the Consolidated Balance Sheet at December 31, 2011, because this intercompany transaction was eliminated in consolidation.

In addition, Centennial, Knife River and MDU Construction Services have issued guarantees to third parties related to the routine purchase of maintenance items, materials and lease obligations for which no fixed maximum amounts have been specified. These guarantees have no scheduled maturity date. In the event a subsidiary of the Company defaults under these obligations, Centennial, Knife River and MDU Construction Services would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these guarantees were reflected on the Consolidated Balance Sheet at December 31, 2011.

In the normal course of business, Centennial has surety bonds related to construction contracts and reclamation obligations of its subsidiaries, as well as an arbitration award. In the event a subsidiary of Centennial does not fulfill a bonded obligation, Centennial would be responsible to the surety bond company for completion of the bonded contract or obligation. A large portion of the surety bonds is expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. As of December 31, 2011, approximately $463 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

Definitions

Abbreviation or Acronym	
AFUDC	Allowance for funds used during construction
Alusa	Tecnica de Engenharia Electrica - Alusa
Army Corps	U.S. Army Corps of Engineers
ASC	FASB Accounting Standards Codification
BART	Best available retrofit technology
Bbl	Barrel
Bcf	Billion cubic feet
Bcfe	Billion cubic feet equivalent
Bicent	Bicent Power LLC
Big Stone Station	450-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
Bitter Creek	Bitter Creek Pipelines, LLC, an indirect wholly owned subsidiary of WBI Holdings
Black Hills Power	Black Hills Power and Light Company
Brazilian Transmission Lines	Company's equity method investment in the company owning ECTE, ENTE and ERTE (ownership interests in ENTE and ERTE were sold in the fourth quarter of 2010 and a portion of the ownership interest in ECTE was sold in the fourth quarter of 2011 and 2010)
Btu	British thermal unit
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
CELESC	Centrais Elétricas de Santa Catarina S.A.
CEM	Colorado Energy Management, LLC, a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
CEMIG	Companhia Energética de Minas Gerais
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Centennial Capital	Centennial Holdings Capital LLC, a direct wholly owned subsidiary of Centennial
Centennial Resources	Centennial Energy Resources LLC, a direct wholly owned subsidiary of Centennial
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
Clean Air Act	Federal Clean Air Act
Clean Water Act	Federal Clean Water Act
Colorado State District Court	Colorado Thirteenth Judicial District Court, Yuma County
Company	MDU Resources Group, Inc.
dk	Decatherm
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
ECTE	Empresa Catarinense de Transmissão de Energia S.A. (7.51 percent ownership interest at December 31, 2011, 2.5 and 14.99 percent ownership interest was sold in 2011 and 2010, respectively)

EIN	Employer Identification Number
ENTE	Empresa Norte de Transmissão de Energia S.A. (entire 13.3 percent ownership interest sold in the fourth quarter of 2010)
EPA	U.S. Environmental Protection Agency
ERISA	Employee Retirement Income Security Act of 1974
ERTE	Empresa Regional de Transmissão de Energia S.A. (entire 13.3 percent ownership interest sold in the fourth quarter of 2010)
ESA	Endangered Species Act
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fidelity	Fidelity Exploration & Production Company, a direct wholly owned subsidiary of WBI Holdings
FIP	Funding improvement plan
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse gas
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company
IBEW	International Brotherhood of Electrical Workers
ICWU	International Chemical Workers Union
IFRS	International Financial Reporting Standards
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
IPUC	Idaho Public Utilities Commission
Item 8	Financial Statements and Supplementary Data
JTL	JTL Group, Inc., an indirect wholly owned subsidiary of Knife River
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
Knife River - Northwest	Knife River Corporation - Northwest, an indirect wholly owned subsidiary of Knife River (previously Morse Bros., Inc., name changed effective January 1, 2010)
K-Plan	Company's 401(k) Retirement Plan
kW	Kilowatts
kWh	Kilowatt-hour
LPP	Lea Power Partners, LLC, a former indirect wholly owned subsidiary of Centennial Resources (member interests were sold in October 2006)
LTM	LTM, Inc., an indirect wholly owned subsidiary of Knife River
LWG	Lower Willamette Group
MAPP	Mid-Continent Area Power Pool
MBbls	Thousands of barrels
Mcf	Thousand cubic feet
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
Mdk	Thousand decatherms
MDU Brasil	MDU Brasil Ltda., an indirect wholly owned subsidiary of Centennial Resources
MDU Construction Services	MDU Construction Services Group, Inc., a direct wholly owned subsidiary of Centennial
MDU Energy Capital	MDU Energy Capital, LLC, a direct wholly owned subsidiary of the Company
Midwest ISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million Btu

MMcf	Million cubic feet
MMcfe	Million cubic feet equivalent - natural gas equivalents are determined using the ratio of six Mcf of natural gas to one Bbl of oil
MMdk	Million decatherms
MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of the Company
Montana DEQ	Montana Department of Environmental Quality
Montana First Judicial District Court	Montana First Judicial District Court, Lewis and Clark County
Montana Seventeenth Judicial District Court	Montana Seventeenth Judicial District Court, Phillips County
MPPAA	Multiemployer Pension Plan Amendments Act of 1980
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
NEPA	National Environmental Policy Act
Oil	Includes crude oil, condensate and natural gas liquids
Omimex	Omimex Canada, Ltd.
OPUC	Oregon Public Utility Commission
Oregon Circuit Court	Circuit Court of the State of Oregon for the County of Klamath
Oregon DEQ	Oregon State Department of Environmental Quality
PCBs	Polychlorinated biphenyls
PDP	Proved developed producing
PRC	Planning resource credit - a MW of demand equivalent assigned to generators by the Midwest ISO for meeting system reliability requirements
Prairielands	Prairielands Energy Marketing, Inc., an indirect wholly owned subsidiary of WBI Holdings
Proxy Statement	Company's 2012 Proxy Statement
PRP	Potentially Responsible Party
PUD	Proved undeveloped
RCRA	Resource Conservation and Recovery Act
ROD	Record of Decision
RP	Rehabilitation plan
Ryder Scott	Ryder Scott Company, L.P.
SDPUC	South Dakota Public Utilities Commission
SEC	U.S. Securities and Exchange Commission
SEC Defined Prices	The average price of natural gas and oil during the applicable 12-month period, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions
Securities Act	Securities Act of 1933, as amended
Securities Act Industry Guide 7	Description of Property by Issuers Engaged or to be Engaged in Significant Mining Operations
Sheridan System	A separate electric system owned by Montana-Dakota
SMCRA	Surface Mining Control and Reclamation Act
SourceGas	SourceGas Distribution LLC
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan
UA	United Association of Journeyman and Apprentices of the Plumbing and Pipefitting Industry of the United States and Canada

WBI Holdings	WBI Holdings, Inc., a direct wholly owned subsidiary of Centennial
Westmoreland	Westmoreland Coal Company
Williston Basin	Williston Basin Interstate Pipeline Company, an indirect wholly owned subsidiary of WBI Holdings
WUTC	Washington Utilities and Transportation Commission
Wygen III	100-MW coal-fired electric generating facility near Gillette, Wyoming (25 percent ownership)
WYPSC	Wyoming Public Service Commission

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2011

	Account Number & Title		Last Year	This Year	% Change
1					
2		**Intangible Plant**			
3					
4	301	Organization			
5	302	Franchises & Consents			
6	303	Miscellaneous Intangible Plant	$4,889,240	$4,999,520	2.26%
7					
8		**TOTAL Intangible Plant**	$4,889,240	$4,999,520	2.26%
9					
10		**Production Plant**			
11					
12	Steam Production				
13					
14	310	Land & Land Rights	$252,286	$245,202	-2.81%
15	311	Structures & Improvements	12,677,153	12,439,715	-1.87%
16	312	Boiler Plant Equipment	42,095,922	41,895,864	-0.48%
17	313	Engines & Engine Driven Generators			
18	314	Turbogenerator Units	11,973,523	11,541,084	-3.61%
19	315	Accessory Electric Equipment	3,833,860	3,839,028	0.13%
20	316	Miscellaneous Power Plant Equipment	4,160,848	3,815,031	-8.31%
21					
22		**TOTAL Steam Production Plant**	$74,993,592	$73,775,924	-1.62%
23					
24	Nuclear Production				
25					
26	320	Land & Land Rights			
27	321	Structures & Improvements			
28	322	Reactor Plant Equipment		NOT	
29	323	Turbogenerator Units		APPLICABLE	
30	324	Accessory Electric Equipment			
31	325	Miscellaneous Power Plant Equipment			
32					
33		**TOTAL Nuclear Production Plant**			
34					
35	Hydraulic Production				
36					
37	330	Land & Land Rights			
38	331	Structures & Improvements			
39	332	Reservoirs, Dams & Waterways		NOT	
40	333	Water Wheels, Turbines & Generators		APPLICABLE	
41	334	Accessory Electric Equipment			
42	335	Miscellaneous Power Plant Equipment			
43	336	Roads, Railroads & Bridges			
44					
45		**TOTAL Hydraulic Production Plant**			

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2011

		Account Number & Title	Last Year	This Year	% Change
1					
2		Production Plant (cont.)			
3					
4	Other Production				
5					
6	340	Land & Land Rights	$16,477	$16,015	-2.80%
7	341	Structures & Improvements	198,414	1,911,471	863.38%
8	342	Fuel Holders, Producers & Accessories	633,222	615,456	-2.81%
9	343	Prime Movers			
10	344	Generators	40,440,939	34,070,544	-15.75%
11	345	Accessory Electric Equipment	271,001	4,234,556	1462.56%
12	346	Miscellaneous Power Plant Equipment	34,374	60,017	74.60%
13					
14		**TOTAL Other Production Plant**	$41,594,427	$40,908,059	-1.65%
15					
16		**TOTAL Production Plant**	$116,588,019	$114,683,983	-1.63%
17					
18		**Transmission Plant**			
19					
20	350	Land & Land Rights	$682,393	$917,666	34.48%
21	352	Structures & Improvements	443	431	-2.71%
22	353	Station Equipment	19,572,341	20,030,668	2.34%
23	354	Towers & Fixtures	1,174,224	1,141,369	-2.80%
24	355	Poles & Fixtures	7,134,857	7,847,999	10.00%
25	356	Overhead Conductors & Devices	5,934,917	6,135,449	3.38%
26	357	Underground Conduit	299,199	290,798	-2.81%
27	358	Underground Conductors & Devices	571,485	555,438	-2.81%
28	359	Roads & Trails			
29					
30		**TOTAL Transmission Plant**	$35,369,859	$36,919,818	4.38%
31					
32		**Distribution Plant**			
33					
34	360	Land & Land Rights	$266,705	$266,705	0.00%
35	361	Structures & Improvements			
36	362	Station Equipment	6,886,982	7,219,869	4.83%
37	363	Storage Battery Equipment			
38	364	Poles, Towers & Fixtures	6,752,360	6,865,432	1.67%
39	365	Overhead Conductors & Devices	5,141,868	5,208,118	1.29%
40	366	Underground Conduit	12,967	12,967	0.00%
41	367	Underground Conductors & Devices	6,873,772	7,136,847	3.83%
42	368	Line Transformers	8,999,714	9,514,029	5.71%
43	369	Services	4,360,652	4,609,910	5.72%
44	370	Meters	2,962,292	3,052,105	3.03%
45	371	Installations on Customers' Premises	748,810	778,786	4.00%
46	372	Leased Property on Customers' Premises			
47	373	Street Lighting & Signal Systems	1,678,831	1,686,196	0.44%
48					
49		**TOTAL Distribution Plant**	$44,684,953	$46,350,964	3.73%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2011

	Account Number & Title		Last Year	This Year	% Change
1					
2		**General Plant**			
3					
4	389	Land & Land Rights	$2,064	$2,061	-0.15%
5	390	Structures & Improvements	120,970	135,830	12.28%
6	391	Office Furniture & Equipment	141,928	210,019	47.98%
7	392	Transportation Equipment	1,285,260	1,282,247	-0.23%
8	393	Stores Equipment	7,904	0	-100.00%
9	394	Tools, Shop & Garage Equipment	520,419	568,305	9.20%
10	395	Laboratory Equipment	210,897	29,550	-85.99%
11	396	Power Operated Equipment	2,085,426	2,012,794	-3.48%
12	397	Communication Equipment	561,238	487,797	-13.09%
13	398	Miscellaneous Equipment	6,523	6,523	0.00%
14	399	Other Tangible Property			
15					
16		**TOTAL General Plant**	$4,942,629	$4,735,126	-4.20%
17					
18		**Common Plant**			
19					
20	389	Land & Land Rights	$219,127	$194,629	-11.18%
21	390	Structures & Improvements	3,888,825	3,720,919	-4.32%
22	391	Office Furniture & Equipment	752,322	637,503	-15.26%
23	392	Transportation Equipment	1,288,620	1,257,951	-2.38%
24	393	Stores Equipment	13,138	13,000	-1.05%
25	394	Tools, Shop & Garage Equipment	178,355	109,028	-38.87%
26	395	Laboratory Equipment			
27	396	Power Operated Equipment	11,665	0	-100.00%
28	397	Communication Equipment	406,855	346,799	-14.76%
29	398	Miscellaneous Equipment	129,541	108,819	-16.00%
30	399	Other Tangible Property			
31					
32		**TOTAL Common Plant**	$6,888,448	$6,388,648	-7.26%
33					
34					
35		**TOTAL Electric Plant in Service**	$213,363,148	$214,078,059	0.34%

MONTANA DEPRECIATION SUMMARY

Year: 2011

	Functional Plant Classification	Plant Cost	Accumulated Depreciation Last Year Bal.	Accumulated Depreciation This Year Bal.	Current Avg. Rate
1					
2	Steam Production 1/	$77,090,456	$61,384,877	$61,255,765	3.12%
3	Nuclear Production				
4	Hydraulic Production				
5	Other Production	40,908,059	5,306,905	6,935,616	4.39%
6	Transmission	36,919,818	18,634,226	18,751,885	1.38%
7	Distribution	46,350,964	23,886,998	24,524,076	2.17%
8	General	6,678,731	3,547,772	3,261,730	3.48%
9	Common	9,444,563	5,942,044	5,613,099	3.55%
10	**TOTAL**	$217,392,591	$118,702,822	$120,342,171	2.89%

MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)

SCHEDULE 21

	Account	Last Year Bal.	This Year Bal.	%Change
1				
2	151 Fuel Stock	$1,446,379	$1,692,096	16.99%
3	152 Fuel Stock Expenses Undistributed			
4	153 Residuals			
5	154 Plant Materials & Operating Supplies:			
6	Assigned to Construction (Estimated)			
7	Assigned to Operations & Maintenance			
8	Production Plant (Estimated)	588,069	582,686	-0.92%
9	Transmission Plant (Estimated)	426,758	1,143,338	167.91%
10	Distribution Plant (Estimated)	660,207	786,182	19.08%
11	Assigned to Other			
12	155 Merchandise			
13	156 Other Materials & Supplies			
14	157 Nuclear Materials Held for Sale			
15	163 Stores Expense Undistributed			
16				
17	**TOTAL Materials & Supplies**	$3,121,413	$4,204,302	34.69%

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS

SCHEDULE 22

	Commission Accepted - Most Recent		% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number	2007.7.79			
2	Order Number	6846f			
3					
4	Common Equity		50.67%	10.25%	5.19%
5	Preferred Stock		3.58%	4.61%	0.17%
6	Long Term Debt		38.18%	7.22%	2.76%
7	Short Term Debt		7.57%	6.11%	0.46%
8	**TOTAL**		100.00%		8.58%
9					
10	Actual at Year End				
11					
12	Common Equity		54.566%	10.250%	5.593%
13	Preferred Stock		2.349%	4.585%	0.108%
14	Long Term Debt		42.790%	6.846%	2.929%
15	Short Term Debt		0.295%	13.053%	0.039%
16	**TOTAL**		100.000%		8.669%

1/ Includes deferred AFUDC, depreciation and interest on Coyote and acquisition adjustment.

STATEMENT OF CASH FLOWS

Year: 2011

	Description	Last Year	This Year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2				
3	**Cash Flows from Operating Activities:**			
4	Net Income	$240,659,282	$213,026,346	-11.48%
5	Depreciation	37,619,293	43,254,010	14.98%
6	Amortization	810,836	799,169	-1.44%
7	Deferred Income Taxes - Net	39,748,983	33,443,170	-15.86%
8	Investment Tax Credit Adjustments - Net	635,810	73,338	-88.47%
9	Change in Operating Receivables - Net	826,147	3,880,302	369.69%
10	Change in Materials, Supplies & Inventories - Net	(1,543,542)	(8,012,994)	-419.13%
11	Change in Operating Payables & Accrued Liabilities - Net	(3,349,647)	10,633,165	417.44%
12	Change in Other Regulatory Assets	(13,370,215)	(38,067,475)	-184.72%
13	Change in Other Regulatory Liabilities	2,507,423	2,245,939	-10.43%
14	Allowance for Other Funds Used During Construction (AFUDC)	(4,268,299)	(2,056,639)	51.82%
15	Change in Other Assets & Liabilities - Net	(9,039,509)	36,086,437	499.21%
16	Less Undistributed Earnings from Subsidiary Companies	(100,425,856)	(75,909,717)	24.41%
17	Other Operating Activities (explained on attached page)			
18	**Net Cash Provided by/(Used in) Operating Activities**	$190,810,706	$219,395,051	14.98%
19				
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment			
22	(net of AFUDC & Capital Lease Related Acquisitions)	($111,818,428)	($77,793,567)	30.43%
23	Acquisition of Other Noncurrent Assets	(6,336,788)	203,053	103.20%
24	Proceeds from Disposal of Noncurrent Assets			
25	Investments In and Advances to Affiliates			
26	Contributions and Advances from Affiliates	(1,636,385)	(3,006,643)	-83.74%
27	Disposition of Investments in and Advances to Affiliates			
28	Other Investing Activities: Depreciation & RWIP on Nonutility Plant	172,190	174,706	1.46%
29	**Net Cash Provided by/(Used in) Investing Activities**	($119,619,411)	($80,422,451)	32.77%
30				
31	**Cash Flows from Financing Activities:**			
32	Proceeds from Issuance of:			
33	Long-Term Debt			
34	Preferred Stock			
35	Common Stock	4,970,954	5,743,321	15.54%
36	Other:	375,227	359,820	-4.11%
37	Net Increase in Short-Term Debt	20,000,000	0	-100.00%
38	Other: Commercial Paper			
39	Payment for Retirement of:			
40	Long-Term Debt	(106,664)	(107,074)	-0.38%
41	Preferred Stock			
42	Common Stock			
43	Other: Adjustment to Retained Earnings	(78,140)	1,798	102.30%
44	Net Decrease in Short-Term Debt	0	(20,000,000)	
45	Dividends on Preferred Stock	(685,004)	(685,003)	0.00%
46	Dividends on Common Stock	(119,496,026)	(123,659,801)	-3.48%
47	Other Financing Activities (related to IGC acquisition)			
48	**Net Cash Provided by (Used in) Financing Activities**	($95,019,653)	($138,346,939)	-45.60%
49				
50	**Net Increase/(Decrease) in Cash and Cash Equivalents**	($23,828,358)	$625,661	102.63%
51	**Cash and Cash Equivalents at Beginning of Year**	$30,103,371	$6,275,013	-79.16%
52	**Cash and Cash Equivalents at End of Year**	$6,275,013	$6,900,674	9.97%

LONG TERM DEBT

Year: 2011

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost % 1/
1	6.61% Senior Notes	09/09	09/16	$25,000,000	$24,414,393	$25,000,000	6.61%	$1,780,000	7.12%
2	6.66% Senior Notes	10/09	09/16	25,000,000	24,414,393	25,000,000	6.66%	1,793,000	7.17%
3	5.98% Senior Notes	12/03	12/33	30,000,000	29,456,832	30,000,000	5.98%	1,861,500	6.21%
4	6.33 % Senior Notes	08/06	08/26	100,000,000	89,123,930	100,000,000	6.33%	7,514,000	7.51%
5	6.04 % Senior Notes	09/08	09/18	100,000,000	99,637,568	100,000,000	6.04%	6,181,000	6.18%
6									
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25									
26	**TOTAL**			$280,000,000	$267,047,116	$280,000,000		$19,129,500	6.83%

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

PREFERRED STOCK

Year: 2011

	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price 1/	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1	4.50 % Cumulative	01/51	100,000	$100	$105	$10,000,000	4.50%	$10,000,000	$450,000	4.50%
2	4.70 % Cumulative	12/55	50,000	100	102	5,000,000	4.70%	5,000,000	235,000	4.70%
3	5.10 % Cumulative 2/	05/61	50,000	100	102	4,947,548	5.29%	400,000	25,500	5.29%
4										
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31										
32	**TOTAL**					$19,947,548		$15,400,000	$710,500	4.61%

1/ Plus accrued dividends.

2/ Mandatory annual redemption of $100,000.

COMMON STOCK

Year: 2011

		Avg. Number of Shares Outstanding 1/	Book Value Per Share	Earnings Per Share 2/	Dividends Per Share	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio 3/
1	January								
2									
3	February								
4									
5	March	188,793,564	$14.16	$0.23	$0.1625	29.35%	$23.00	$20.11	17.9
6									
7	April								
8									
9	May								
10									
11	June	188,793,564	14.36	0.24	0.1625	32.29%	24.05	21.47	17.9
12									
13	July								
14									
15	August								
16									
17	September	188,793,564	14.70	0.34	0.1625	52.21%	23.28	18.25	15.1
18									
19	October								
20									
21	November								
22									
23	December	188,793,564	14.62	0.32	0.1675	47.66%	22.19	18.00	19.2
24									
25									
26									
27									
28									
29									
30	TOTAL Year End	188,793,564	$14.62	$1.13	$0.6550	42.04%			19.2

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

MONTANA EARNED RATE OF RETURN

Year: 2011

	Description	Last Year	This Year	% Change
	Rate Base			
1				
2	101 Plant in Service 1/	$214,345,783	$214,892,242	0.25%
3	108 (Less) Accumulated Depreciation 2/	116,302,748	117,954,549	1.42%
4				
5	**NET Plant in Service**	$98,043,035	$96,937,693	-1.13%
6				
7	CWIP in Service Pending Reclassification	$809,867	$1,274,249	57.34%
8				
9	Additions			
10	151 Fuel Stocks	$1,446,379	$1,692,096	16.99%
11	154, 156 Materials & Supplies	1,675,034	2,512,206	49.98%
12	165 Prepayments	40,315	37,703	-6.48%
13	189 Unamortized Loss on Debt	1,522,801	1,282,639	-15.77%
14				
15	**TOTAL Additions**	$4,684,529	$5,524,644	17.93%
16				
17	Deductions			
18	190 Accumulated Deferred Income Taxes	$18,161,212	$22,437,962	23.55%
19	252 Customer Advances for Construction	492,450	402,657	-18.23%
20	255 Accumulated Def. Investment Tax Credits	3,476	19	-99.45%
21	Other Deductions			
22				
23	**TOTAL Deductions**	$18,657,138	$22,840,638	22.42%
24	**TOTAL Rate Base**	$84,880,293	$80,895,948	-4.69%
25				
26	**Net Earnings**	$6,416,074	$8,479,063	32.15%
27				
28	**Rate of Return on Average Rate Base**	8.33%	10.23%	22.81%
29				
30	**Rate of Return on Average Equity**	9.75%	13.11%	34.46%
31	Major Normalizing Adjustments & Commission			
32	Ratemaking Adjustments to Utility Operations			
33	Adjustments to Operating Revenues 3/			
34	Late Payment Revenues	$15,348	$15,097	-1.64%
35	Gain from Disposition of Property 4/	3,345	18,105	441.26%
36				
37	Adjustments to Operating Expenses 3/			
38	Elimination of Promotional & Institutional Advertising	(5,357)	(9,982)	-86.34%
39	Elimination of Supplemental Insurance	146,420	(137,831)	-194.13%
40				
41	Adjustments to Tax Deductions			
42	Elimination of 401K Tax Deduction	151,424	128,035	-15.45%
43				
44	Other Adjustments to Federal & State Income Taxes			
45	Federal & State Out of Period & Closing/Filing		2,239,730	N/A
46	Deferred Federal & State Out of Period & Closing/Filing		(1,764,992)	N/A
47				
48	Total Adjustments to Operating Income	($273,794)	($421,758)	54.04%
49				
50	**Adjusted Rate of Return on Average Rate Base**	7.97%	9.72%	21.96%
51				
52	**Adjusted Rate of Return on Average Equity**	9.08%	12.18%	34.14%

1/ Excludes Acquisition Adjustment of $2,572,583 for 2010 and $2,500,349 for 2011.
2/ Excludes Acquisition Adjustment of $2,400,074 for 2010 and $2,387,622 for 2011.
3/ Updated amounts, net of taxes.
4/ Amortized over 5 years.

MONTANA COMPOSITE STATISTICS

Year: 2011

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	$212,125
5	107	Construction Work in Progress	2,800
6	114	Plant Acquisition Adjustments	
7	105	Plant Held for Future Use	
8	154, 156	Materials & Supplies	2,512
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	117,955
11	252	Contributions in Aid of Construction	403
12			
13		**NET BOOK COSTS**	$99,079
14			
15		Revenues & Expenses (000 Omitted)	
16			
17	400	Operating Revenues	$51,565
18			
19	403 - 407	Depreciation & Amortization Expenses	$6,283
20		Federal & State Income Taxes	1,144
21		Other Taxes	3,402
22		Other Operating Expenses	32,257
23		TOTAL Operating Expenses	$43,086
24			
25		Net Operating Income	$8,479
26			
27		Other Income	469
28		Other Deductions	3,050
29			
30		**NET INCOME**	$5,898
31			
32		Customers (Intrastate Only)	
33			
34		Year End Average:	
35		Residential	18,606
36		Small General	5,503
37		Large General	277
38		Other	200
39			
40		**TOTAL NUMBER OF CUSTOMERS**	24,586
41			
42		Other Statistics (Intrastate Only)	
43			
44		Average Annual Residential Use (Kwh))	9,672
45		Average Annual Residential Cost per (Kwh) (Cents) * 1/	$0.083
46		* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
47		Average Residential Monthly Bill	$66.90
48		Gross Plant per Customer	$8,628

1/ Reflects average revenue for 2011.

MONTANA CUSTOMER INFORMATION

Year: 2011

	City/Town	Population (Includes Rural) 1/	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Antelope	51	61	20	2	83
2	Bainville	208	118	44	7	169
3	Baker	1,741	977	353	13	1,343
4	Brockton	255	102	25	3	130
5	Carlyle	Not Available	2	5		7
6	Culbertson	714	356	144	5	505
7	Fallon	164	179	109	1	289
8	Fairview	840	407	102	3	512
9	Flaxville	71	55	27	3	85
10	Forsyth	1,777	1,030	287	10	1,327
11	Froid	185	142	49	4	195
12	Glendive	4,935	3,327	829	36	4,192
13	Homestead	Not Available	20	9	1	30
14	Ismay	19	22	19	1	42
15	Kinsey	Not Available	112	54		166
16	Medicine Lake	225	181	53	4	238
17	Miles City	8,410	4,538	1,046	39	5,623
18	Outlook	47	55	37	13	105
19	Plentywood	1,734	954	264	6	1,224
20	Plevna	162	93	31	3	127
21	Poplar	810	875	174	14	1,063
22	Poplar Oil Field	Not Available		7	10	17
23	Redstone	Not Available	16	19	1	36
24	Reserve	23	25	13	3	41
25	Rosebud	111	69	63	3	135
26	Savage	Not Available	136	32	2	170
27	Scobey	1,017	595	177	3	775
28	Sidney	5,191	2,454	509	25	2,988
29	Terry	605	354	106	10	470
30	Whitetail	Not Available	26	25	1	52
31	Wibaux	589	295	101	8	404
32	Wolf Point	2,621	1,465	333	8	1,806
33	MT Oil Fields	Not Available	8	69	90	167
34	**TOTAL Montana Customers**	32,505	19,049	5,135	332	24,516

1/ 2010 Census.

MONTANA EMPLOYEE COUNTS 1/

Year: 2011

	Department	Year Beginning	Year End	Average
1	Electric	20	20	20
2	Gas	40	40 (1)	40 (1)
3	Accounting	8	7	8
4	Management	5	4	5
5	Service	31	29	30
6	Communications/Substation/Training	1	2	1
7	Power Production	32	33	32
8				
9				
10				
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43				
44	**TOTAL Montana Employees**	137 (0)	135 (1)	136 (1)

1/ Parentheses denotes part-time.

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 31**

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED)

Year: 2011

	Project Description	Total Company	Total Montana	
1	Projects>$1,000,000			
2	Common-General			
3	Construct District Office in Williston, ND	$2,571,439	$787,458	1/
4	Common-Intangible			
5	Replace Customer Information System	4,977,499	1,383,669	1/
6	Purchase Powerplan Plant/Tax/Budgeting Software	1,019,975	250,438	1/
7	Electric-Steam Production			
8	Upgrade Material Handling System for Coal/Limestone-Heskett	6,215,066	1,495,992	1/
9	Replace Induced Draft Fan Variable Frequency Drive-L&C	1,479,432	356,105	1/
10	Install Technology for Air Quality Control-Big Stone	13,211,414	3,180,144	1/
11	Replace Generator Stator Windings-Coyote	1,173,376	282,436	1/
12	Electric-Other Production			
13	Install 88MW Combustion Turbine in ND	20,040,364	4,824,995	1/
14	Demolish Williston Steam and Other Production Plant	2,314,994	557,229	1/
15	Electric-Distribution			
16	Upgrade 26th & D substation to 115KV-Bismarck, ND	1,336,111	0	
17	Electric-Transmission			
18	Construct 115/41.6KV W junction substation-Dickinson, ND	2,776,280	533,322	1/
19	Rebuild Transmission Line from Glendive to Baker, MT	1,602,833	1,602,833	2/
20	Install 115KV Oilfield Line Tap from Glendive to Baker, MT	1,863,932	1,863,932	2/
21	Construct 115KV Substation-Keystone Pipeline-Baker, MT	1,666,653	1,666,653	2/
22	Construct 230KV line for Merricourt Windfarm	6,258,299	1,507,484	1/
23	Other Projects<$1,000,000			
24	Electric			
25	Production	15,142,687	3,510,728	1/
26	Integrated Transmission	3,361,804	766,309	1/
27	Direct Transmission	2,784,300	291,012	2/
28	Distribution	18,581,640	3,473,269	2/
29	General	2,785,666	577,520	1/
30	Common:			
31	General Office	3,652,461	823,599	1/
32	Other Direct	538,645	53,379	2/
33	Total Electric	46,847,203	9,495,816	
34	Gas			
35	Production	0	0	
36	Distribution	17,205,038	4,640,519	1/
37	General	2,981,378	582,157	2/
38	Intangible	42,600	12,508	2/
39	Common:			
40	General Office	2,371,355	709,456	1/
41	Other Direct	231,588	46,744	2/
42	Total Gas	22,831,959	5,991,384	
43	TOTAL	$138,186,829	$35,779,890	

1/ Allocated to Montana.

2/ Directly assigned to Montana.

TOTAL INTEGRATED SYSTEM & MONTANA PEAK AND ENERGY

Year: 2011

Integrated System

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	Jan.	31	2000	457.7	290,778	3,656
2	Feb.	1	2000	448.7	246,518	2,208
3	Mar.	1	2000	432.1	251,001	797
4	Apr.	19	1000	359.5	205,123	142
5	May	10	1200	328.9	209,659	11,642
6	Jun.	29	1900	474.7	209,109	10,077
7	Jul.	19	1700	535.7	269,806	17,212
8	Aug.	22	1800	488.3	262,441	14,775
9	Sep.	8	1800	418.9	210,525	3,342
10	Oct.	5	1700	379.3	230,642	
11	Nov.	21	1000	414.9	255,473	37
12	Dec.	5	1900	447.8	258,373	11
13	**TOTAL**				2,899,448	63,899

Montana

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
14	Jan.	31	2000	101.9		
15	Feb.	1	2000	106.1		
16	Mar.	1	2000	101.6		
17	Apr.	19	1000	71.1		
18	May	10	1200	74.4		
19	Jun.	29	1900	112.8		
20	Jul.	19	1700	117.8	Not Available	Not Available
21	Aug.	22	1800	109.6		
22	Sep.	8	1800	105.4		
23	Oct.	5	1700	75.2		
24	Nov.	21	1000	91.9		
25	Dec.	5	1900	104.4		
26	**TOTAL**					

TOTAL SYSTEM Sources & Disposition of Energy

SCHEDULE 33

	Sources	Megawatthours	Disposition	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	2,271,288	Sales to Ultimate Consumers	
3	Nuclear		(Include Interdepartmental)	2,878,852
4	Hydro - Conventional			
5	Hydro - Pumped Storage		Requirements Sales	
6	Other	217,049	for Resale	
7	(Less) Energy for Pumping			
8	**NET Generation**	2,488,337	Non-Requirements Sales	
9	Purchases	641,320	for Resale	63,899
10	Power Exchanges			
11	Received	55,610	Energy Furnished	
12	Delivered	51,363	Without Charge	
13	**NET Exchanges**	4,247		
14	Transmission Wheeling for Other		Energy Used Within	
15	Received	1,537,747	Electric Utility	
16	Delivered	1,445,735		
17	**NET Transmission Wheeling**	92,012	Total Energy Losses	252,282
18	Transmission by Others Losses	(30,883)		
19	**TOTAL**	3,195,033	**TOTAL**	3,195,033

Montana-Dakota's annual peak occurred during HE1700 July 19, 2011. All generation units were available for operation during the peak hour. The following units were on line and providing energy.

Big Stone	101.9
Cedar Hills	1.3
Coyote	98.9
Diamond Willow	0.4
Glendive Turbine	55.2
Glen Ullin Ormat	4.6
Heskett #1	20.7
Heskett #2	69.7
Lewis & Clark	38.5

Montana-Dakota also purchased 111.37 Mw from MISO to meet the peak demand. The remaining demand was purchased from Western Area Power Administration through Balancing Authority services and was paid back in-kind the following month.

SOURCES OF ELECTRIC SUPPLY

Year: 2011

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Combustion Turbine	Williston Plant	Williston, ND	0.00	(68.2)
2	Combustion Turbine	Miles City Turbine	Miles City, MT	20.90	218.6
3	Thermal	Lewis & Clark Station	Sidney, MT	53.06	300,782.4
4	Combustion Turbine	Glendive Turbine	Glendive, MT	73.71	15,430.7
5	Thermal	Heskett Station	Mandan, ND	102.87	500,080.4
6	Thermal	Big Stone Station	Milbank, SD	107.76	508,057.7
7				(MDU SHARE)	
8	Thermal	Coyote Station	Beulah, ND	107.03	755,778.7
9				(MDU SHARE)	
10	Wind	Diamond Willow	Baker, MT	30.45	98,867.4
11	Heat Recovery	Glen Ullin Ormat Sub	Glen Ullin, ND	6.50	43,132.8
12	Wind	Cedar Hills	Rhame, ND	20.06	59,467.7
13					
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41					
42					
43	**Total**			522.34	2,281,748.2

Outage Start Date/Time	Outage End Date/Time	Brief Description of Primary Cause 1/
		Big Stone Plant: Unit #1
01/01/2011 00:00	01/01/2011 01:29	Primary superheat tube leak repairs
01/18/2011 10:18	01/18/2011 11:46	Blew a fuse to the master fuel trip relay
04/01/2011 18:24	04/03/2011 04:14	Boiler tube leaks
08/06/2011 10:20	08/07/2011 20:45	Tube leak
08/08/2011 04:17	08/09/2011 23:32	Tube leak
08/30/2011 16:04	08/30/2011 18:04	Boiler feed pump lube oil pump trip
09/14/2011 19:57	11/18/2011 20:01	2011 fall outage
11/20/2011 15:43	11/20/2011 18:04	Intercept valves closed
11/21/2011 19:10	11/21/2011 20:43	Boiler feed pump trip
11/21/2011 20:55	11/22/2011 01:02	Low drum level
11/22/2011 11:07	11/22/2011 13:00	Manual turbine trip sticking
11/28/2011 13:23	11/29/2011 23:58	High pressure feedwater heater turbine gland leakoff line steam leak
		Coyote Station: Unit #1
02/20/2011 22:26	02/22/2011 22:52	Roof tube failure
03/17/2011 22:08	03/21/2011 05:26	Cleaning boiler due to slag buildup
04/29/2011 00:26	04/30/2011 01:02	Upper cyclone tube leak
06/02/2011 21:56	06/12/2011 04:24	Scheduled maintenance outage
06/24/2011 21:06	06/26/2011 17:11	Screen tube failure
07/22/2011 08:53	07/22/2011 10:51	Low "B" bus voltage plant trip (potential transformer fuse)
08/27/2011 00:26	08/28/2011 12:32	Secondary superheat tube leak
08/28/2011 12:40	08/28/2011 16:33	Load center trouble
09/09/2011 11:24	09/11/2011 09:00	Secondary superheat tube leak
09/11/2011 23:00	09/13/2011 06:01	#4 cyclone tube leak
09/13/2011 10:20	09/14/2011 18:38	#4 cyclone tube leak
09/22/2011 21:49	09/26/2011 04:39	Scheduled boiler wash outage
12/08/2011 22:06	12/12/2011 05:15	Scheduled maintenance outage
		Lewis & Clark Station: Unit #1
02/04/2011 05:31	02/04/2011 16:38	Scrubber disk cleaning
03/03/2011 08:08	03/03/2011 14:54	Variable frequency drive cooling block leak
04/16/2011 21:32	04/20/2011 10:00	Blown water wall tube
04/20/2011 10:00	05/09/2011 08:36	Planned spring outage
05/25/2011 01:17	05/26/2011 04:59	Replace leaking valve
08/23/2011 22:42	08/24/2011 07:10	Add oil to 115 KV bushing on generator step up transformer
09/29/2011 20:52	10/11/2011 10:44	Planned fall outage
		R.M. Heskett Station: Unit #1
04/09/2011 00:01	04/09/2011 12:45	High pressure feedwater heater drain line to dearating feedwater heater steam leak
05/18/2011 21:52	05/28/2011 04:00	Maintenance outage
09/23/2011 18:27	10/06/2011 05:42	Maintenance outage
12/05/2011 18:57	12/28/2011 10:16	Main generator step up transformer fault
12/28/2011 13:38	12/28/2011 16:24	Change tap settings on main transformer

1/ Outages longer than 1 hour, other than reserve shutdowns for economic dispatch.

Outage Start Date/Time	Outage End Date/Time	Brief Description of Primary Cause 1/
		R.M. Heskett Station: Unit #2
03/21/2011 19:55	03/23/2011 23:30	Inbed generating tube leaks
03/23/2011 23:30	04/03/2011 08:00	Scheduled spring outage
04/03/2011 08:00	04/29/2011 09:47	Generator high voltage bushing repair
04/30/2011 02:37	05/04/2011 14:06	Waterwall tube leak
05/06/2011 22:55	05/07/2011 18:28	Steam leak on west crossover piping
10/07/2011 22:57	10/22/2011 06:17	Schedueled maintenance outage
12/05/2011 18:57	12/06/2011 13:43	Unit 1 generator step up transformer fault cleared sub
12/06/2011 17:52	12/06/2011 21:18	High drum level, feedwater regulator valve tripped

1/ Outages longer than 1 hour, other than reserve shutdowns for economic dispatch.

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2011

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings **(MW & MWH)**	Achieved Savings **(MW & MWH)**	Difference **(MW & MWH)**
1							
2	MT Conservation & DSM Program	$3,576	$8,913	-59.88%	N/A	42.3 MWh	N/A
3	(As Detailed on Schedule 35B)						
4							
5							
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30							
31							
32	**TOTAL**	$3,576	$8,913	-59.88%	N/A	42.3 MWh	N/A

Company Name: Montana-Dakota Utilities Co. SCHEDULE 35A

ELECTRIC UNIVERSAL SYSTEM BENEFITS PROGRAMS

Year: 2011

	Program Description	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (MW and MWh)	Most recent program evaluation
1	Local Conservation					
2	Commercial Lighting	$1,890	$0	$1,890	42.1 MWh	2011
3	Energy Star Refrig/Freezers	1,686	0	1,686	0.2 MWh	2011
4						
5						
6						
7	Market Transformation					
8						
9						
10						
11						
12						
13	Renewable Resources					
14						
15						
16						
17						
18						
19	Research & Development					
20						
21						
22						
23						
24						
25	Low Income					
26	Discounts	$295,009	$0	$295,009		2011
27						
28	Bill Assistance	45,000	0	45,000		2011
29						
30	Conservation	162,000	0	162,000		2011
31						
32	Furnace Safety	50,000	0	50,000		2011
33						
34	Education	3,178	0	3,178		2011
35	Large Customer Self Directed					
36		$33,765	$0	$33,765		
37						
38						
39						
40						
41	Total	$592,528	$0	$592,528	42.3 MWh	2011
42	Number of customers that received low income rate discounts			(Average)	1,612	
43	Average monthly bill discount amount ($/mo)				$15.27	
44	Average LIEAP-eligible household income				N/A	
45	Number of customers that received weatherization assistance				N/A	
46	Expected average annual bill savings from weatherization				N/A	
47	Number of residential audits performed				N/A	

Company Name: Montana-Dakota Utilities Co. SCHEDULE 35B

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS Year: 2011

	Program Description	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (MW and MWh)	Most recent program evaluation
1	Local Conservation					
2	Commercial Lighting	$1,890	$0	$1,890	42.1 MWh	2011
3	Energy Star Refrig/Freezers	1,686	0	1,686	0.2 MWh	2011
4						
5						
6						
7						
8	Demand Response					
9						
10						
11						
12						
13						
14						
15	Market Transformation					
16						
17						
18						
19						
20						
21						
22	Research & Development					
23						
24						
25						
26						
27						
28						
29	Low Income					
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35	Other					
36						
37						
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41						
42						
43						
44						
45						
46	Total	$3,576	$0	$3,576	42.3 MWh	2011

MONTANA CONSUMPTION AND REVENUES

Year: 2011

	Sales of Electricity	Operating Revenues Current Year	Operating Revenues Previous Year	MegaWatt Hours Sold Current Year	MegaWatt Hours Sold Previous Year	Avg. No. of Customers Current Year	Avg. No. of Customers Previous Year
1	Residential	$14,938,802	$13,365,135	179,961	167,616	18,606	18,458
2	Small General	8,811,963	7,956,486	117,846	110,960	5,503	5,388
3	Large General	23,496,466	20,579,717	432,552	416,097	277	262
4	Lighting	841,263	790,290	9,971	9,863	93	87
5	Municipal Pumping	416,506	389,026	7,232	6,974	107	105
6	Sales to Other Utilities	452,611	430,201	Not Applicable	Not Applicable	Not Applicable	Not Applicable
7							
8							
9							
10							
11							
12							
13	**TOTAL**	$48,957,611	$43,510,855	747,562	711,510	24,586	24,300