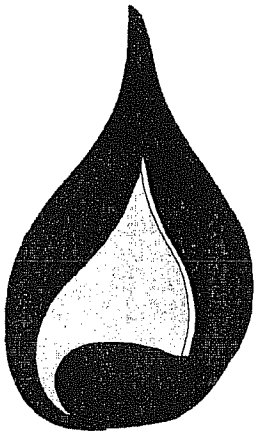
Response No. MCC-092
Attachment B

YEAR ENDING 2011

ANNUAL REPORT
OF

MONTANA-DAKOTA UTILITIES CO.

GAS UTILITY



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

REVISED 2005

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.	
12		
13		
14		
15		
16		
17		
18		

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	
15			
16			
17			
18			
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CORPORATE STRUCTURE

Year: 2011

	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			
7				
8	WBI Holdings, Inc.	Pipeline and Energy Services and	103,364	48.68%
9		Natural Gas and Oil Production		
10				
11	Knife River Corporation	Construction Materials and	26,430	12.45%
12		Mining		
13				
14	MDU Construction Services	Construction Services	21,627	10.18%
15	Group, Inc.			
16				
17	Centennial Energy Resources LLC/	Other	(6,736)	-3.17%
18	Centennial Holdings Capital LLC			
19				
20				
21				
22				
23				
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25				
26				
27				
28				
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49				
50	**TOTAL**		$212,341	100.00%

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 5

CORPORATE ALLOCATIONS - GAS

Year: 2011

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Audit Costs	Administrative & General	Various Corporate Overhead Allocation Factors	$2,922	1.67%	$172,173
2						
3	Advertising	Administrative & General	Various Corporate Overhead Allocation Factors and/or	6,433	1.71%	369,461
4			Actual Costs Incurred			
5						
6	Air Service	Administrative & General	Various Corporate Overhead Allocation Factors, Time	1,065	1.28%	82,219
7			Studies, and/or Actual Costs Incurred			
8						
9	Automobile	Administrative & General	Various Corporate Overhead Allocation Factors, Time	457	1.82%	24,686
10			Studies, and/or Actual Costs Incurred			
11						
12	Bank Services	Administrative & General	Various Corporate Overhead Allocation Factors and/or	5,948	1.67%	350,191
13			Actual Costs Incurred			
14						
15	Computer Rental	Administrative & General	Various Corporate Overhead Allocation Factors, Time	90	1.67%	5,306
16			Studies, and/or Actual Costs Incurred			
17						
18	Consultant Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or	9,659	1.61%	590,606
19			Actual Costs Incurred			
20						
21	Contract Services	Administrative & General	Various Corporate Overhead Allocation Factors and/or	25,505	1.41%	1,789,027
22			Actual Costs Incurred			
23						
24	Corporate Aircraft	Administrative & General	Various Corporate Overhead Allocation Factors, Time	1,893	1.71%	108,674
25			Studies, and/or Actual Costs Incurred			
26						
27	Directors Expenses	Administrative & General	Corporate Overhead Allocation Factor Based on a	32,704	1.67%	1,925,209
28			Combination of Net Plant Investment and Number			
29			of Employees			
30						
31	Employee Benefits	Administrative & General	Corporate Overhead Allocation Factor Based on	2,882	1.68%	168,910
32			Number of Employees			

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 5

CORPORATE ALLOCATIONS - GAS

Year: 2011

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Employee Meetings	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	2,256	1.68%	132,081
2						
3						
4	Employee Reimbursable Expenses	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	2,388	1.46%	161,514
5						
6						
7	Legal Retainers & Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	18,487	1.67%	1,087,496
8						
9						
10	Meal Allowance	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	40	1.66%	2,373
11						
12						
13	Meals & Entertainment	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	1,759	1.55%	111,822
14						
15						
16	Moving Expense	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	84	1.68%	4,916
17						
18						
19	Industry Dues & Licenses	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	2,484	1.66%	147,413
20						
21						
22	Office Expenses	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	1,508	1.90%	78,034
23						
24						
25	Prepaid Insurance	Administrative & General	Various Corporate Overhead Allocation Factors and Allocation Factors Based on Actual Experience	18,256	1.50%	1,202,203
26						
27						
28	Permits and Filing Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	662	2.17%	29,849
29						
30						
31	Postage	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	368	1.80%	20,028
32						

SCHEDULE 5

Company Name: Montana-Dakota Utilities Co.

CORPORATE ALLOCATIONS - GAS

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	363,178	1.82%	19,542,371
2						
3						
4	Reimbursements	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	(889)	1457.38%	828
5						
6						
7	Rental	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	71	1.89%	3,679
8						
9						
10	Reference Materials	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	3,170	1.72%	181,197
11						
12						
13	Seminars & Meeting	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	1,435	1.69%	83,707
14	Registrations					
15						
16	Software Maintenance	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	9,596	1.68%	560,858
17						
18						
19	Supplemental Insurance	Administrative & General	Various Corporate Overhead Factors	47,927	1.68%	2,805,418
20						
21	Telephone & Cell Phones	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	2,958	1.23%	238,319
22						
23						
24	Training Material	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	1,006	1.92%	51,350
25						
26						
27						
28						
29						
30						
31						
32	**TOTAL**			$566,302	1.74%	$32,031,918

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

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		$2,743		$2,039
3		Office Expense		2,524		643
4		Travel		168		
5						
6		Capital	Actual Costs Incurred			
7		Contract Services		2,638		2,638
8		Materials		10,592		9,718
9						
10		Other				
11		Balance Sheet Accts	Actual Costs Incurred	335,556		
12		MDU Resources Cost Centers		8,031		
13		Non Utility		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**		$363,108	0.0240%	$15,038

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

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**	Natural Gas	Actual Costs Incurred			
2		Purchases/Transportation		$54,426,155		$16,901,243
3						
4		Expense	Actual Costs Incurred			
5		Contract Services		20,955		12,070
6		Materials		10,580		6,951
7		Miscellaneous		8,631		2,178
8						
9		Capital	Actual Costs Incurred			
10		Contract Services		201,337		54,606
11		Materials		38,504		6,303
12						
13						
14		Other	Actual Costs Incurred			
15		Auto Clearing		14,731		
16		Balance sheet accounts		1,028,253		
17		Non Utility		11,014		
18		MDU Resources Cost Centers		12,474		
19						
20		Total WBI Holdings, Inc. Operating Revenues for the Year 2011			$731,929,000	
21		Excludes Intersegment Eliminations				
22						
23						
24	**TOTAL**	**Grand Total Affiliate Transactions**		$55,772,634	7.6200%	$16,983,351

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

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**	Contract Services		$4,482		$4,126
3						
4		Capital				
5		Contract Services	Actual Costs Incurred	147,095		147,095
6		Materials		269		88
7						
8		Other	Actual Costs Incurred			
9		MDU Resources Cost Centers		11,601		
10		Auto Clearing		88		
11		Non Utility		1,980		
12						
13						
14						
15		Total MDU Construction Services Group, Inc Operating Revenues for the Year 2011			$854,389,000	
16		Excludes Intersegment Eliminations				
17						
18						
19						
20						
21						
22	**TOTAL**	**Grand Total Affiliate Transactions**		$165,515	0.0194%	$151,309

Company Name: Montana-Dakota Utilities Co. SCHEDULE 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2011

Line	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**CENTENNIAL HOLDINGS**	Expense	* Various Corporate Overhead			
2	**CAPITAL, LLC**	Contract Services	Allocation Factors and/or	$84,989		$21,652
3		Corporate Aircraft	Actual Costs Incurred	25,886		4,978
4		Office Expense		170,410		43,413
5		Rent		110,535		28,160
6		Other		21		
7						
8		Capital	Actual Costs Incurred			
9		Corporate Aircraft		543		158
10		Materials		4,195		1,112
11		Other		1,115		330
12						
13		Other	Actual Costs Incurred			
14		MDU Resources Cost Centers		348,255		
15		Balance Sheet Accts		2,100,089		
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		Excludes Intersegment Eliminations				
21						
22	**TOTAL**	**Grand Total Affiliate Transactions**		$3,364,455	29.3942%	$99,803

* 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 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

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		$40,624		$11,773
3		Cost of Service		14,681		3,740
4		Materials		3,463		882
5		Office Expenses		55,543		16,842
6		Other		3,440		982
7		Travel				
8						
9						
10		Capital	Actual Costs Incurred			
11		Contract Services		18,427		4,764
12		Materials		17,881		4,772
13		Other		339		84
14						
15						
16						
17		Other Transactions/Reimbursements	Actual Costs Incurred			
18		MDU Resources Cost Centers		2,529		
19		Auto Clearing		3,248		
20		Customer Advances		8,300		
21		Subsidiary Receivables		1,897		
22		Miscellaneous		1,160		
23		Non Utility		49,416		
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**		$220,948	0.0359%	$43,839

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.

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 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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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	**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			

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 ****	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						

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 ****	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 Allocaion		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.

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	**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	$70,844,518	$74,110,974	4.61%
2					
3		Operating Expenses			
4	401	Operation Expenses	$60,092,529	$62,625,234	4.21%
5	402	Maintenance Expense	923,110	979,108	6.07%
6	403	Depreciation Expense	2,683,837	2,900,311	8.07%
7	404-405	Amort. & Depl. of Gas Plant	132,050	110,987	-15.95%
8	406	Amort. of Gas Plant Acquisition Adjustments			
9	407.1	Amort. of Property Losses, Unrecovered Plant			
10		& Regulatory Study Costs			
11	407.2	Amort. of Conversion Expense			
12	408.1	Taxes Other Than Income Taxes	3,126,339	3,308,019	5.81%
13	409.1	Income Taxes - Federal	(828,689)	(2,219,553)	-167.84%
14		- Other	(181,972)	(710,633)	-290.52%
15	410.1	Provision for Deferred Income Taxes	1,535,952	3,034,219	97.55%
16	411.1	(Less) Provision for Def. Inc. Taxes - Cr.	279,367	454,982	62.86%
17	411.4	Investment Tax Credit Adjustments			
18	411.6	(Less) Gains from Disposition of Utility Plant			
19	411.7	Losses from Disposition of Utility Plant			
20		**TOTAL Utility Operating Expenses**	$67,762,523	$70,482,674	4.01%
21		**NET UTILITY OPERATING INCOME**	$3,081,995	$3,628,300	17.73%

MONTANA REVENUES

SCHEDULE 9

	Account Number & Title		Last Year	This Year	% Change
1		Sales of Gas			
2	480	Residential	$43,725,041	$45,522,909	4.11%
3	481	Commercial & Industrial - Small	26,373,205	28,100,036	6.55%
4		Commercial & Industrial - Large	1,161	107,192	9132.73%
5	482	Other Sales to Public Authorities			
6	484	Interdepartmental Sales			
7	485	Intracompany Transfers			
8		Net Unbilled Revenue	(845,627)	(1,240,879)	-46.74%
9		**TOTAL Sales to Ultimate Consumers**	69,253,780	72,489,258	4.67%
10	483	Sales for Resale			
11		**TOTAL Sales of Gas**	$69,253,780	$72,489,258	4.67%
12		Other Operating Revenues			
13	487	Forfeited Discounts & Late Payment Revenues			
14	488	Miscellaneous Service Revenues	$39,596	$45,335	14.49%
15	489	Revenues from Transp. of Gas for Others 1/	1,269,502	1,252,889	-1.31%
16	490	Sales of Products Extracted from Natural Gas			
17	491	Revenues from Nat. Gas Processed by Others			
18	492	Incidental Gasoline & Oil Sales			
19	493	Rent From Gas Property	237,171	244,710	3.18%
20	494	Interdepartmental Rents			
21	495	Other Gas Revenues	44,469	78,782	77.16%
22		**TOTAL Other Operating Revenues**	1,590,738	1,621,716	1.95%
23		**Total Gas Operating Revenues**	$70,844,518	$74,110,974	4.61%
24					
25	496	(Less) Provision for Rate Refunds			
26					
27		**TOTAL Oper. Revs. Net of Pro. for Refunds**	$70,844,518	$74,110,974	4.61%

1/ Includes unbilled revenue.

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2011

	Account Number & Title		Last Year	This Year	% Change
1		**Production Expenses**			
2	Production & Gathering - Operation				
3	750	Operation Supervision & Engineering			
4	751	Production Maps & Records			
5	752	Gas Wells Expenses			
6	753	Field Lines Expenses			
7	754	Field Compressor Station Expenses	$0	$185,343	
8	755	Field Compressor Station Fuel & Power			
9	756	Field Measuring & Regulating Station Expense			
10	757	Purification Expenses			
11	758	Gas Well Royalties			
12	759	Other Expenses			
13	760	Rents			
14		**Total Operation - Natural Gas Production**	$0	$185,343	
15	Production & Gathering - Maintenance				
16	761	Maintenance Supervision & Engineering			
17	762	Maintenance of Structures & Improvements			
18	763	Maintenance of Producing Gas Wells			
19	764	Maintenance of Field Lines			
20	765	Maintenance of Field Compressor Sta. Equip.	$0	$3,215	
21	766	Maintenance of Field Meas. & Reg. Sta. Equip.			
22	767	Maintenance of Purification Equipment			
23	768	Maintenance of Drilling & Cleaning Equip.			
24	769	Maintenance of Other Equipment			
25		**Total Maintenance- Natural Gas Prod.**	$0	$3,215	
26		**TOTAL Natural Gas Production & Gathering**	$0	$188,558	
27	Products Extraction - Operation				
28	770	Operation Supervision & Engineering			
29	771	Operation Labor			
30	772	Gas Shrinkage			
31	773	Fuel			
32	774	Power			
33	775	Materials			
34	776	Operation Supplies & Expenses		NOT	
35	777	Gas Processed by Others		APPLICABLE	
36	778	Royalties on Products Extracted			
37	779	Marketing Expenses			
38	780	Products Purchased for Resale			
39	781	Variation in Products Inventory			
40	782	(Less) Extracted Products Used by Utility - Cr.			
41	783	Rents			
42		**Total Operation - Products Extraction**			
43	Products Extraction - Maintenance				
44	784	Maintenance Supervision & Engineering			
45	785	Maintenance of Structures & Improvements			
46	786	Maintenance of Extraction & Refining Equip.			
47	787	Maintenance of Pipe Lines		NOT	
48	788	Maintenance of Extracted Prod. Storage Equip.		APPLICABLE	
49	789	Maintenance of Compressor Equipment			
50	790	Maintenance of Gas Meas. & Reg. Equip.			
51	791	Maintenance of Other Equipment			
52		**Total Maintenance - Products Extraction**			
53		**TOTAL Products Extraction**			

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2011

	Account Number & Title	Last Year	This Year	% Change
1	**Production Expenses - continued**			
2				
3	Exploration & Development - Operation			
4	795 Delay Rentals			
5	796 Nonproductive Well Drilling		NOT	
6	797 Abandoned Leases		APPLICABLE	
7	798 Other Exploration			
8	**TOTAL Exploration & Development**			
9				
10	Other Gas Supply Expenses - Operation			
11	800 Natural Gas Wellhead Purchases			
12	800.1 Nat. Gas Wellhead Purch., Intracomp. Trans.			
13	801 Natural Gas Field Line Purchases			
14	802 Natural Gas Gasoline Plant Outlet Purchases			
15	803 Natural Gas Transmission Line Purchases			
16	804 Natural Gas City Gate Purchases	$54,182,782	$54,043,985	-0.26%
17	805 Other Gas Purchases			
18	805.1 Purchased Gas Cost Adjustments	(2,548,511)	52,393	102.06%
19	805.2 Incremental Gas Cost Adjustments			
20	806 Exchange Gas			
21	807.1 Well Expenses - Purchased Gas			
22	807.2 Operation of Purch. Gas Measuring Stations			
23	807.3 Maintenance of Purch. Gas Measuring Stations			
24	807.4 Purchased Gas Calculations Expenses			
25	807.5 Other Purchased Gas Expenses			
26	808.1 Gas Withdrawn from Storage -Dr.	11,166,035	11,534,089	3.30%
27	808.2 (Less) Gas Delivered to Storage -Cr.	(11,661,945)	(12,895,437)	-10.58%
28	809.2 (Less) Deliveries of Nat. Gas for Processing-Cr.			
29	810 (Less) Gas Used for Compressor Sta. Fuel-Cr.			
30	811 (Less) Gas Used for Products Extraction-Cr.			
31	812 (Less) Gas Used for Other Utility Operations-Cr.			
32	813 Other Gas Supply Expenses	89,297	73,609	-17.57%
33	**TOTAL Other Gas Supply Expenses**	$51,227,658	$52,808,639	3.09%
34				
35	**TOTAL PRODUCTION EXPENSES**	$51,227,658	$52,997,197	3.45%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2011

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

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2011

	Account Number & Title		Last Year	This Year	% Change
1		**Transmission Expenses**			
2	Operation				
3	850	Operation Supervision & Engineering			
4	851	System Control & Load Dispatching			
5	852	Communications System Expenses			
6	853	Compressor Station Labor & Expenses			
7	854	Gas for Compressor Station Fuel		NOT	
8	855	Other Fuel & Power for Compressor Stations		APPLICABLE	
9	856	Mains Expenses			
10	857	Measuring & Regulating Station Expenses			
11	858	Transmission & Compression of Gas by Others			
12	859	Other Expenses			
13	860	Rents			
14		**Total Operation - Transmission**			
15	Maintenance				
16	861	Maintenance Supervision & Engineering			
17	862	Maintenance of Structures & Improvements			
18	863	Maintenance of Mains			
19	864	Maintenance of Compressor Station Equip.		NOT	
20	865	Maintenance of Measuring & Reg. Sta. Equip.		APPLICABLE	
21	866	Maintenance of Communication Equipment			
22	867	Maintenance of Other Equipment			
23		**Total Maintenance - Transmission**			
24		**TOTAL Transmission Expenses**			
25		**Distribution Expenses**			
26	Operation				
27	870	Operation Supervision & Engineering	$471,700	$514,850	9.15%
28	871	Distribution Load Dispatching	75,294	74,482	-1.08%
29	872	Compressor Station Labor and Expenses			
30	873	Compressor Station Fuel and Power			
31	874	Mains and Services Expenses	1,143,489	1,138,366	-0.45%
32	875	Measuring & Reg. Station Exp.-General	47,011	34,815	-25.94%
33	876	Measuring & Reg. Station Exp.-Industrial	9,177	14,521	58.23%
34	877	Meas. & Reg. Station Exp.-City Gate Ck. Sta.			
35	878	Meter & House Regulator Expenses	391,269	267,551	-31.62%
36	879	Customer Installations Expenses	517,434	538,992	4.17%
37	880	Other Expenses	851,664	832,223	-2.28%
38	881	Rents	34,763	33,379	-3.98%
39		**Total Operation - Distribution**	$3,541,801	$3,449,179	-2.62%
40	Maintenance				
41	885	Maintenance Supervision & Engineering	$115,484	$130,671	13.15%
42	886	Maintenance of Structures & Improvements	1,394	1,179	-15.42%
43	887	Maintenance of Mains	141,425	138,093	-2.36%
44	888	Maint. of Compressor Station Equipment			
45	889	Maint. of Meas. & Reg. Station Exp.-General	10,292	28,158	173.59%
46	890	Maint. of Meas. & Reg. Sta. Exp.-Industrial	6,885	15,721	128.34%
47	891	Maint. of Meas. & Reg. Sta. Equip.-City Gate			
48	892	Maintenance of Services	160,415	155,111	-3.31%
49	893	Maintenance of Meters & House Regulators	268,882	284,028	5.63%
50	894	Maintenance of Other Equipment	105,407	120,738	14.54%
51		**Total Maintenance - Distribution**	$810,184	$873,699	7.84%
52		**TOTAL Distribution Expenses**	$4,351,985	$4,322,878	-0.67%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2011

	Account Number & Title		Last Year	This Year	% Change
1					
2		**Customer Accounts Expenses**			
3	Operation				
4	901	Supervision	$118,807	$96,853	-18.48%
5	902	Meter Reading Expenses	258,366	230,640	-10.73%
6	903	Customer Records & Collection Expenses	1,221,296	1,376,127	12.68%
7	904	Uncollectible Accounts Expenses	147,990	173,361	17.14%
8	905	Miscellaneous Customer Accounts Expenses	86,442	71,102	-17.75%
9					
10		**TOTAL Customer Accounts Expenses**	$1,832,901	$1,948,083	6.28%
11					
12		**Customer Service & Informational Expenses**			
13	Operation				
14	907	Supervision	$29,102	$28,530	-1.97%
15	908	Customer Assistance Expenses	9,092	11,125	22.36%
16	909	Informational & Instructional Advertising Exp.	17,436	29,420	68.73%
17	910	Miscellaneous Customer Service & Info. Exp.	166	20,025	11963.25%
18					
19		**TOTAL Customer Service & Info. Expenses**	$55,796	$89,100	59.69%
20					
21		**Sales Expenses**			
22	Operation				
23	911	Supervision	$25,177	$22,825	-9.34%
24	912	Demonstrating & Selling Expenses	85,629	72,732	-15.06%
25	913	Advertising Expenses	10,630	12,258	15.32%
26	916	Miscellaneous Sales Expenses	15,587	11,758	-24.57%
27					
28		**TOTAL Sales Expenses**	$137,023	$119,573	-12.74%
29					
30		**Administrative & General Expenses**			
31	Operation				
32	920	Administrative & General Salaries	$975,671	$956,138	-2.00%
33	921	Office Supplies & Expenses	485,811	548,659	12.94%
34	922	(Less) Administrative Expenses Transferred - Cr.			
35	923	Outside Services Employed	75,401	123,948	64.39%
36	924	Property Insurance	88,943	80,637	-9.34%
37	925	Injuries & Damages	252,136	263,668	4.57%
38	926	Employee Pensions & Benefits	1,212,733	1,837,400	51.51%
39	927	Franchise Requirements			
40	928	Regulatory Commission Expenses	10,718	1,742	-83.75%
41	929	(Less) Duplicate Charges - Cr.			
42	930.1	General Advertising Expenses	17,712	18,504	4.47%
43	930.2	Miscellaneous General Expenses	49,863	78,885	58.20%
44	931	Rents	128,362	115,735	-9.84%
45					
46		**TOTAL Operation - Admin. & General**	$3,297,350	$4,025,316	22.08%
47	Maintenance				
48	935	Maintenance of General Plant	$112,926	$102,194	-9.50%
49					
50		**TOTAL Administrative & General Expenses**	$3,410,276	$4,127,510	21.03%
51	**TOTAL OPERATION & MAINTENANCE EXP.**		$61,015,639	$63,604,341	4.24%

MONTANA TAXES OTHER THAN INCOME

Year: 2011

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes	$480,741	$428,471	-10.87%
2	Secretary of State	276	286	3.62%
3	Highway Use Tax	203	210	3.45%
4	Montana Consumer Counsel	34,647	83,064	139.74%
5	Montana PSC	193,003	272,846	41.37%
6	Delaware Franchise Taxes	17,913	19,066	6.44%
7	Property Taxes	2,393,648	2,497,882	4.35%
8	Tribal Taxes	5,908	6,194	4.84%
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50	**TOTAL MT Taxes other than Income**	$3,126,339	$3,308,019	5.81%

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

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS 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		0.00%
4					
5	AFPI	Annual Report Preparation	141,890	$2,386	1.68%
6					
7	American Gas Association	Industrial Membership	99,847	25,215	25.25%
8					
9	API Construction Co.	Contractor Services - Power Plant	113,992		0.00%
10					
11	Atlantic Plant Services	Contract Services - Environmental	95,495		0.00%
12					
13	B & B Foundation Service Inc.	Construction Service	154,705		0.00%
14					
15	Barr Engineering Company	Engineering Services	196,927		0.00%
16					
17	Benco Equipment Co.	Vehicle Maintenance	224,033		0.00%
18					
19	Bismarck-Mandan Area	Promotional-MDU Resources	251,634	4,176	1.66%
20	Chamber of Commerce	Bowl Naming Rights			
21	Blue Heron	Consulting Services	1,351,467	270,619	20.02%
22					
23	Brink Construction Inc.	Contract Services - Storm Replacement	2,260,227		0.00%
24					
25	Broadridge	Contract Services - Shareholder	132,602	2,230	1.68%
26					
27	Bullinger Tree Services	Tree Trimming	363,080		0.00%
28					
29	Butler Machinery Co.	Equipment Maintenance	85,463		0.00%
30					
31	Central Trenching	Contract Services - Trenching	270,025		0.00%
32					
33	CGI Technologies & Solutions	Replace Mobile Workforce Software	134,843	6,896	5.11%
34					
35	Chief Construction	Construction Service	755,342	869	0.12%
36					
37	Cisco Systems Capital Corp.	Software Maintenance	121,222	1,207	1.00%
38					
39	Clean Harbors Environmental	Replace U1-Boiling Bank Tubes-Heskett	118,185	1,116	0.94%
40	Services	and Gas PCB Pickup			
41	Cohen, Tauber, Spievack &	Legal Services	341,674	5,331	1.56%
42	Wagner, PC				
43	Connecting Point	Computer Services & Software Maint.	78,522	9,443	12.03%
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		0.00%
50					

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

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

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Dakota Tree Service	Tree Trimming	160,363		0.00%
2					
3	Deloitte & Touche LLP	Auditing & Consulting Services	923,638	35,441	3.84%
4					
5	Denny's Electric Motor Repair	Line Extension & Pipe Extensions	155,494	17,670	11.36%
6					
7	Dewey & LeBoeuf	Legal Services	759,144	28,678	3.78%
8					
9	Dorsey & Whitney, LLP	Legal Services	104,208	1,529	1.47%
10					
11	Edison Electric Institute	Industrial Membership	100,300		0.00%
12					
13	EP2M	Consulting Services	1,498,175	299,996	20.02%
14					
15	Eide Ford Mercury Lincoln Inc.	Auto Maintenance	80,469		0.00%
16					
17	Environmental Plant Services	Contract Services - Environmental	77,850		0.00%
18					
19	Fischer Contracting	Construction Services - Gas	318,904		0.00%
20					
21	Franz Construction Inc.	Contract Services - Power Plant	460,254		0.00%
22					
23	Forrester, Gary	Lobbying & Promotion	104,082	1,736	1.67%
24					
25	GE Energy Services	Contractor Services - Power Plant	227,895		0.00%
26					
27	Gagnon Inc.	Contractor Services - Heskett Station	518,516		0.00%
28					
29	General Electric International	Contractor Services	346,955		0.00%
30					
31	Govert Powerline Services	Contractor Services - Install Lighting Arresters	288,212		0.00%
32					
33	Hardy Construction	Contractor Services - Billings Landfill	203,273	58,404	28.73%
34					
35	HDR Engineering Inc.	Engineering Services	729,906		0.00%
36					
37	High Point Networks	Contractor Services	82,169	14,345	17.46%
38					
39	Highmark, Inc.	Construction Services	1,877,065		0.00%
40					
41	Honeywell Industry Solutions	Equipment Installation	100,138		0.00%
42					
43	Hughes, Kellner, Sullivan & Alke PLLP	Legal Services	77,704	40,383	51.97%
44					
45	Industrial Contractors Inc.	Contract Services - Power Plant	489,732		0.00%
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					

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

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

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Itron Inc.	Contractor Services - Software Maint.	188,697	41,058	21.76%
2					
3	J.B. Construction Inc.	Contractor Services - Line Replacement	266,750		0.00%
4					
5	Kappel Tree Service, LLP	Tree Trimming	252,872		0.00%
6					
7	LFG Technologies Develop. LLC	Contractor Services - Billings Landfill	150,136	43,137	28.73%
8					
9	McDermott, Will & Emery LLP	Legal Services	76,332	2,022	2.65%
10					
11	MCM General Contractors, Inc.	Construction Services	512,586		0.00%
12					
13	Microsoft Licensing GP	Software Maintenance	302,151	11,450	3.79%
14					
15	Midwest ISO	Contractor Services	315,537		0.00%
16					
17	Millcreek Engineering Company	Engineering Services	277,333		0.00%
18					
19	Moorhead Machinery & Boiler	Contractor Services - Power Plant	1,507,407		0.00%
20					
21	New York Life	Consulting Services	190,566	7,156	3.76%
22					
23	Norby Inc.	Trucking - Sidney	77,040		0.00%
24					
25	North American Electric	NERC & MRO Region Assessment	80,088		0.00%
26					
27	NYSE Market Inc.	Financial Services	177,598	2,986	1.68%
28					
29	One Call Locaters	Line Location Services	1,093,001	201,451	18.43%
30					
31	Open Systems International, Inc.	EMS Upgrade - Replacement	2,344,626		0.00%
32					
33	Oracle Corporation	Software Maintenance	375,768	37,122	9.88%
34					
35	Ormat Nevada Inc.	Energy Convertor Maint. Agreement	206,694		0.00%
36					
37	Otter Tail Power Co.	Transmission Line Repair	77,199		0.00%
38					
39	Pearce, Harry J.	Active Directors Fees	130,000	2,169	1.67%
40					
41	Power Generations Service Inc.	Contract Services - Power Plants	171,137		0.00%
42					
43	Progressive Maintenance	Custodial Service	134,747	11,811	8.77%
44					
45	Prosource Tech Inc.	Contract Services - Environmental	536,359	313	0.06%
46					
47	PSC Industrial Outsourcing	Contractor Services - Power Plant	742,662		0.00%
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 - GAS Year: 2011

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Rocky Mountain Contractors, Inc.	Contractor Services	234,612	151,221	64.46%
2					
3	Southern Cross Corporation	Construction Services	225,826	63,051	27.92%
4					
5	Spherion Corporation	Temp Service	332,821	8,937	2.69%
6					
7	SQLSoft Consulting Group	Consulting Services - Replace CIS	79,625	15,944	20.02%
8					
9	Standard & Poors	Financial Services	159,680	5,296	3.32%
10					
11	State Line Contractors Inc.	Constructions Services	376,699	359,071	95.32%
12					
13	Telvent USA Corporation	Software Development	101,377	4,780	4.72%
14					
15	Timberline Construction Inc.	Contractors Services-Transmission Lines	657,957		0.00%
16					
17	Total Corrosion Solutions Inc.	Contractor Services	77,372	54,606	70.58%
18					
19	Transystems LLC	Haul Charges	75,230		0.00%
20					
21	Treasury Management Services	Banking Services	298,699	49,069	16.43%
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	48,764	29.36%
28					
29	Utility Partners, Inc.	Maintenance Renewal	85,800	14,093	16.43%
30					
31	Utility Shareholders of ND	Organizational Dues	97,500		0.00%
32					
33	Van Horn Media	Advertising	92,192	6,875	7.46%
34					
35	Ventyx Energy LLC	Software Maintenance	95,010		0.00%
36					
37	Wells Fargo Shareowners Services	Stock Transfer Agent	283,244	4,719	1.67%
38					
39	Western Engineered Solutions	Contract Services - Heskett	121,997		0.00%
40					
41	Workforce Services	Vehicle Maintenance	181,112	5,784	3.19%
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50					
51	**TOTAL Payments for Services**		$34,875,919	$1,980,555	5.68%

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

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 Fiinancial Accounting Standards Board Accounting Standards Codification Topic 718 - Share Based Payment.

The compensation committee may consider the policy and the executive's stock ownership in determining compensation. The committee, however, did not do so with respect to 2011 compensation.

Policy Regarding Hedging Stock Ownership

Our executive compensation policy prohibits Section 16 officers from hedging their ownership of company common stock. Executives may not enter into transactions that allow the executive to benefit from devaluation of our stock or otherwise own stock technically but without the full benefits and risks of such ownership.

Compensation Committee Report

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

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

Summary Compensation Table for 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 Services Group, Inc.	2009	450,000	–	402,417	–	392,500 (6)	761,670	23,272 (5)	2,029,859
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 & Production Company	2009	–	–	–	–	–	–	–	–
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

(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

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%

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

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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	Gas Plant in Service	$316,055,894	$333,770,850	5.61%
4	101.1	Property Under Capital Leases			
5	102	Gas Plant Purchased or Sold			
6	104	Gas Plant Leased to Others			
7	105	Gas Plant Held for Future Use			
8	105.1	Production Properties Held for Future Use			
9	106	Completed Constr. Not Classified - Gas			
10	107	Construction Work in Progress - Gas	3,300,246	2,626,272	-20.42%
11	108	(Less) Accumulated Depreciation	(177,243,810)	(183,602,702)	3.59%
12	111	(Less) Accumulated Amortization & Depletion	(1,202,954)	(1,304,859)	8.47%
13	114	Gas Plant Acquisition Adjustments	97,266	97,266	0.00%
14	115	(Less) Accum. Amort. Gas Plant Acq. Adj.	(49,572)	(52,392)	5.69%
15	116	Other Gas Plant Adjustments			
16	117	Gas Stored Underground - Noncurrent	3,560,347	3,551,913	-0.24%
17	118	Other Utility Plant	1,064,505,411	1,112,249,369	4.49%
18	119	Accum. Depr. and Amort. - Other Utl. Plant	(495,246,117)	(514,132,722)	3.81%
19		**TOTAL Utility Plant**	$713,776,711	$753,202,995	5.52%
20	**Other Property & Investments**				
21	121	Nonutility Property	$4,168,474	$4,345,368	4.24%
22	122	(Less) Accum. Depr. & Amort. of Nonutil. Prop.	(1,311,967)	(1,460,122)	11.29%
23	123	Investments in Associated Companies			
24	123.1	Investments in Subsidiary Companies	2,336,133,125	2,402,890,906	2.86%
25	124	Other Investments	48,037,819	47,834,766	-0.42%
26	125	Sinking Funds			
27		**TOTAL Other Property & Investments**	$2,387,027,451	$2,453,610,918	2.79%
28	**Current & Accrued Assets**				
29	131	Cash	$6,238,148	$6,845,910	9.74%
30	132-134	Special Deposits	1,200	1,200	0.00%
31	135	Working Funds	36,865	54,764	48.55%
32	136	Temporary Cash Investments			
33	141	Notes Receivable			
34	142	Customer Accounts Receivable	29,395,116	26,202,128	-10.86%
35	143	Other Accounts Receivable	4,363,648	2,785,945	-36.16%
36	144	(Less) Accum. Provision for Uncollectible Accts.	(231,003)	(237,599)	2.86%
37	145	Notes Receivable - Associated Companies			
38	146	Accounts Receivable - Associated Companies	27,836,855	28,733,840	3.22%
39	151	Fuel Stock	5,029,867	5,921,977	17.74%
40	152	Fuel Stock Expenses Undistributed			
41	153	Residuals and Extracted Products			
42	154	Plant Materials and Operating Supplies	10,139,125	14,611,115	44.11%
43	155	Merchandise	876,220	915,028	4.43%
44	156	Other Material & Supplies			
45	163	Stores Expense Undistributed	(639)	0	100.00%
46	164.1	Gas Stored Underground - Current	18,538,439	21,147,886	14.08%
47	165	Prepayments	4,438,120	4,929,924	11.08%
48	166	Advances for Gas Explor., Devl. & Production			
49	171	Interest & Dividends Receivable			
50	172	Rents Receivable			
51	173	Accrued Utility Revenues	37,326,027	31,824,896	-14.74%
52	174	Miscellaneous Current & Accrued Assets			
53		**TOTAL Current & Accrued Assets**	$143,987,988	$143,737,014	-0.17%

BALANCE SHEET

	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	This 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			
12	230	Asset Retirement Obligations	6,314,471	6,645,275	5.24%
13		**TOTAL Other Noncurrent Liabilities**	$62,208,703	$80,617,849	29.59%
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	$3,590,537,109	4.49%

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.

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.*

	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		**Intangible Plant**			
2					
3	301	Organization			
4	302	Franchises & Consents			
5	303	Miscellaneous Intangible Plant	$2,753,557	$2,876,903	4.48%
6					
7		**TOTAL Intangible Plant**	$2,753,557	$2,876,903	4.48%
8					
9		**Production Plant**			
10					
11	Production & Gathering Plant				
12					
13	325.1	Producing Lands			
14	325.2	Producing Leaseholds			
15	325.3	Gas Rights			
16	325.4	Rights-of-Way			
17	325.5	Other Land & Land Rights			
18	326	Gas Well Structures			
19	327	Field Compressor Station Structures			
20	328	Field Meas. & Reg. Station Structures			
21	329	Other Structures			
22	330	Producing Gas Wells-Well Construction			
23	331	Producing Gas Wells-Well Equipment			
24	332	Field Lines			
25	333	Field Compressor Station Equipment	$2,972,781	$3,096,756	4.17%
26	334	Field Meas. & Reg. Station Equipment			
27	335	Drilling & Cleaning Equipment			
28	336	Purification Equipment			
29	337	Other Equipment			
30	338	Unsuccessful Exploration & Dev. Costs			
31					
32		**Total Production & Gathering Plant**	$2,972,781	$3,096,756	4.17%
33					
34	Products Extraction Plant				
35					
36	340	Land & Land Rights			
37	341	Structures & Improvements			
38	342	Extraction & Refining Equipment			
39	343	Pipe Lines		NOT	
40	344	Extracted Products Storage Equipment		APPLICABLE	
41	345	Compressor Equipment			
42	346	Gas Measuring & Regulating Equipment			
43	347	Other Equipment			
44					
45		**Total Products Extraction Plant**			
46					
47	**TOTAL Production Plant**		2,972,781	3,096,756	4.17%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2011

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

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2011

	Account Number & Title		Last Year	This Year	% Change
1					
2		**Distribution Plant**			
3					
4	374	Land & Land Rights	$38,808	$38,808	0.00%
5	375	Structures & Improvements	195,164	195,164	0.00%
6	376	Mains	28,343,409	28,903,239	1.98%
7	377	Compressor Station Equipment			
8	378	Meas. & Reg. Station Equipment-General	575,341	577,021	0.29%
9	379	Meas. & Reg. Station Equipment-City Gate	128,221	128,222	0.00%
10	380	Services	19,708,913	21,208,457	7.61%
11	381	Meters	17,741,728	18,493,911	4.24%
12	382	Meter Installations			
13	383	House Regulators	1,908,710	2,130,129	11.60%
14	384	House Regulator Installations			
15	385	Industrial Meas. & Reg. Station Equipment	187,825	187,825	0.00%
16	386	Other Prop. on Customers' Premises	148,674	148,673	0.00%
17	387	Other Equipment	1,128,322	1,238,827	9.79%
18					
19		**TOTAL Distribution Plant**	$70,105,115	$73,250,276	4.49%
20					
21		**General Plant**			
22					
23	389	Land & Land Rights	$7,131	$7,131	0.00%
24	390	Structures & Improvements	449,416	449,416	0.00%
25	391	Office Furniture & Equipment	113,320	114,001	0.60%
26	392	Transportation Equipment	2,297,976	2,373,101	3.27%
27	393	Stores Equipment	43,786	14,254	-67.45%
28	394	Tools, Shop & Garage Equipment	836,041	686,193	-17.92%
29	395	Laboratory Equipment	37,072	32,303	-12.86%
30	396	Power Operated Equipment	1,719,060	1,941,611	12.95%
31	397	Communication Equipment	434,804	377,589	-13.16%
32	398	Miscellaneous Equipment	15,112	15,109	-0.02%
33	399	Other Tangible Property			
34					
35		**TOTAL General Plant**	$5,953,718	$6,010,708	0.96%
36					
37		**Common Plant**			
38					
39	389	Land & Land Rights	$952,893	$988,648	3.75%
40	390	Structures & Improvements	7,115,215	6,978,927	-1.92%
41	391	Office Furniture & Equipment	829,861	901,341	8.61%
42	392	Transportation Equipment	1,016,316	1,074,612	5.74%
43	393	Stores Equipment	10,796	10,773	-0.21%
44	394	Tools, Shop & Garage Equipment	157,383	125,817	-20.06%
45	396	Power Operated Equipment	6,458	0	-100.00%
46	397	Communication Equipment	424,299	360,021	-15.15%
47	398	Miscellaneous Equipment	125,964	112,540	-10.66%
48					
49		**TOTAL Common Plant**	$10,639,185	$10,552,679	-0.81%
50					
51		**TOTAL Gas Plant in Service**	$92,424,356	$95,787,322	3.64%

Company Name: Montana-Dakota Utilities Co. SCHEDULE 20

MONTANA DEPRECIATION SUMMARY

Year: 2011

	Functional Plant Classification	Plant Cost	Accumulated Depreciation Last Year Bal.	Accumulated Depreciation This Year Bal.	Current Avg. Rate
1	Production & Gathering	$3,096,756	$0	$101,594	3.28%
2	Products Extraction				
3	Underground Storage				
4	Other Storage				
5	Transmission				
6	Distribution	73,250,276	42,010,598	43,776,099	3.23%
7	General	6,066,112	3,337,813	3,129,071	1.90%
8	Common	13,374,178	4,948,159	5,215,031	3.19%
9	**TOTAL**	$95,787,322	$50,296,570	$52,221,795	3.14%

MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)

SCHEDULE 21

	Account	Last Year Bal.	This Year Bal.	%Change
1				
2	151 Fuel Stock			
3	152 Fuel Stock Expenses - Undistributed			
4	153 Residuals & Extracted Products			
5	154 Plant Materials & Operating Supplies:			
6	Assigned to Construction (Estimated)			
7	Assigned to Operations & Maintenance			
8	Production Plant (Estimated)			
9	Transmission Plant (Estimated)			
10	Distribution Plant (Estimated)	$508,979	$557,694	9.57%
11	Assigned to Other			
12	155 Merchandise			
13	156 Other Materials & Supplies			
14	163 Stores Expense Undistributed			
15				
16	**TOTAL Materials & Supplies**	$508,979	$557,694	9.57%

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS

SCHEDULE 22

	Commission Accepted - Most Recent		% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number	D95.7.90			
2	Order Number	5856b			
3					
4	Common Equity		44.810%	12.000%	5.377%
5	Preferred Stock		1.810%	4.653%	0.084%
6	Long Term Debt		53.390%	10.212%	5.452%
7					
8	**TOTAL**				10.913%
9					
10	Actual at Year End				
11					
12	Common Equity		54.566%	12.000%	6.548%
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%		9.624%

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%

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 24

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%
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24									
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.

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 26

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	$92,424,356	$95,787,322	3.64%
3	108	(Less) Accumulated Depreciation	50,296,570	52,221,795	3.83%
4					
5		**NET Plant in Service**	$42,127,786	$43,565,527	3.41%
6					
7		CWIP in Service Pending Reclassification	$442,264	$500,474	13.16%
8					
9		Additions			
10	154, 156	Materials & Supplies	$508,979	$557,694	9.57%
11	165	Prepayments	23,075	28,741	24.55%
12		Prepaid Demand/Commodity Charges	1,086,349	1,213,615	11.72%
13		Gas in Underground Storage	6,702,686	7,566,845	12.89%
14	189	Unamortized Loss on Debt	631,135	538,504	-14.68%
15	182	Other Regulatory Assets	148,226	109,558	-26.09%
16					
17		**TOTAL Additions**	$9,100,450	$10,014,957	10.05%
18					
19		Deductions			
20	190	Accumulated Deferred Income Taxes	$7,621,484	$10,230,508	34.23%
21	252	Customer Advances for Construction	770,737	683,775	-11.28%
22	255	Accumulated Def. Investment Tax Credits	6,977	1,191	-82.93%
23					
24		**TOTAL Deductions**	$8,399,198	$10,915,474	29.96%
25		**TOTAL Rate Base**	$43,271,302	$43,165,484	-0.24%
26					
27		**Net Earnings**	$3,081,995	$3,628,300	17.73%
28					
29		**Rate of Return on Average Rate Base**	7.25%	8.40%	15.86%
30					
31		**Rate of Return on Average Equity**	7.72%	9.76%	26.42%
32		Major Normalizing Adjustments & Commission			
33		Ratemaking Adjustments to Utility Operations			
34		Adjustments to Operating Revenues 1/			
35		Weather Normalization	$98,566	($649,024)	-758.47%
36		Late Payment Revenue	26,530	27,791	4.75%
38		Gain from Disposition of Utility Plant 2/	41,025	17,264	-57.92%
39		Penalty Revenue 3/	22,398	(9,901)	-144.20%
40					
41		Adjustments to Operating Expenses 1/			
42		Elimination of Promotional & Institutional Advertising	(17,179)	(18,646)	-8.54%
43		Elimination of Supplemental Insurance	108,105	(120,747)	-211.69%
44					
45		Adjustments to Tax Deductions			
46		Elimination of 401K Tax Deduction	192,098	207,785	8.17%
47					
48		Other Adjustments to Federal & State Income Taxes			
49		Federal & State Out of Period & Closing/Filing		1,560,882	N/A
50		Deferred Federal & State Out of Period & Closing/Filing		(1,302,970)	N/A
51					
52		Total Adjustments to Operating Income	($94,505)	($940,174)	-894.84%
53					
54		**Adjusted Rate of Return on Average Rate Base**	7.03%	6.22%	-11.52%
55					
56		**Adjusted Rate of Return on Average Equity**	7.31%	5.76%	-21.20%

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

MONTANA COMPOSITE STATISTICS

Year: 2011

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	$97,611
5	107	Construction Work in Progress	427
6	114	Plant Acquisition Adjustments	
7	104	Plant Leased to Others	
8	105	Plant Held for Future Use	
9	154, 156	Materials & Supplies	558
10		(Less):	
11	108, 111	Depreciation & Amortization Reserves	52,222
12	252	Contributions in Aid of Construction	684
13			
14		**NET BOOK COSTS**	$45,690
15			
16		Revenues & Expenses (000 Omitted)	
17			
18	400	Operating Revenues	$74,111
19			
20	403 - 407	Depreciation & Amortization Expenses	$3,011
21		Federal & State Income Taxes	559
22		Other Taxes	3,308
23		Other Operating Expenses	63,605
24		TOTAL Operating Expenses	$70,483
25			
26		Net Operating Income	$3,628
27			
28		Other Income	838
29		Other Deductions	1,548
30			
31		**NET INCOME**	$2,918
32			
33		Customers (Intrastate Only)	
34			
35		Year End Average:	
36		Residential	69,976
37		Firm General	8,558
38		Small Interruptible	44
39		Large Interruptible	5
40			
41		**TOTAL NUMBER OF CUSTOMERS**	78,583
42			
43		Other Statistics (Intrastate Only)	
44			
45		Average Annual Residential Use (Dkt))	90
46		Average Annual Residential Cost per (Dkt) ($) * 1/	$7.27
47		* Avg annual cost = [(cost per Dkt x annual use) + (monthly service charge x 12)]/annual use	
48		Average Residential Monthly Bill	$54.53
49		Gross Plant per Customer	$1,242

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	Belfry	218	126	17		143
2	Billings	104,170	45,504	4,488		49,992
3	Bridger	708	417	63		480
4	Crow Agency	1,616	298	77		375
5	Edgar	114	105	6		111
6	Fromberg	438	277	16		293
7	Hardin	3,505	1,245	197		1,442
8	Joliet	595	359	42		401
9	Laurel	6,718	3,834	272		4,106
10	Park City	983	630	27		657
11	Pryor	618	92	14		106
12	Rockvale	Not Available	69	4		73
13	Silesia	96	31	2		33
14	Warren	Not Available	0	2		2
15	Alzada	29	11	7		18
16	Baker	1,741	803	183		986
17	Carlyle	Not Available	7	1		8
18	Fort Peck	233	131	10		141
19	Fairview	840	374	57		431
20	Forsyth	1,777	866	153		1,019
21	Frazer	362	97	16		113
22	Glasgow	3,250	1,621	322		1,943
23	Glendive	4,935	3,097	424		3,521
24	Hinsdale	217	114	23		137
25	Ismay	19	11	5		16
26	Malta	1,997	994	202		1,196
27	Miles City	8,410	3,909	564		4,473
28	Nashua	290	162	24		186
29	Poplar	810	839	133		972
30	Richey	177	116	25		141
31	Rosebud	111	43	7		50
32	Saco	197	40	6		46
33	Savage	Not Available	148	20		168
34	Sidney	5,191	2,434	438		2,872
35	Terry	605	313	59		372
36	St. Marie	264	221	12		233
37	Wibaux	589	218	50		268
38	Whitewater	64	27	9		36
39	Wolf Point	2,621	1,351	203		1,554
40	MT Oil Fields	Not Available	1	3		4
41	**TOTAL Montana Customers**	154,508	70,935	8,183	0	79,118

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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40				
41				
42				
43				
44	**TOTAL Montana Employees**	137 (0)	135 (1)	136 (1)

1/ Parentheses denotes part-time.

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-Hesl	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.

TRANSMISSION SYSTEM - TOTAL COMPANY & MONTANA

Year: 2011

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

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

DISTRIBUTION SYSTEM - TOTAL COMPANY & MONTANA

Year: 2011

	Total Company			
		Peak Day of Month	Peak Day Volumes Dkt	Total Monthly Volumes Dkt
1	January	31	312,370	7,121,265
2	February	1	304,840	6,207,742
3	March	1	259,769	5,349,893
4	April	3	161,782	3,671,807
5	May	1	121,999	2,559,229
6	June	9	68,799	1,596,462
7	July	27	53,899	1,387,879
8	August	30	52,433	1,390,670
9	September	21	75,104	1,707,754
10	October	26	142,045	2,988,569
11	November	19	231,879	4,781,235
12	December	5	243,476	5,757,149
13	**TOTAL**			44,519,654

	Montana			
		Peak Day of Month	Peak Day Volumes Dkt	Total Monthly Volumes Dkt
14	January	31	98,115	2,125,527
15	February	1	95,316	1,944,566
16	March	1	76,903	1,471,140
17	April	22	50,349	1,166,074
18	May	29	37,441	916,197
19	June	9	26,493	595,577
20	July	27	22,990	542,844
21	August	30	23,389	526,888
22	September	1	30,624	637,203
23	October	27	46,784	991,832
24	November	19	73,955	1,557,216
25	December	5	73,562	1,729,564
26	**TOTAL**			14,204,628

STORAGE SYSTEM - TOTAL COMPANY & MONTANA

Year: 2011

		Total Company						
		Peak Day of Month		Peak Day Volumes (Dkt)		Total Monthly Volumes (Dkt)		
		Injection	Withdrawal	Injection	Withdrawal	Injection	Withdrawal	Losses
1	January	27	31	1,855	175,592	13,543	3,008,393	
2	February	15	1	4,000	174,898	18,635	2,668,742	
3	March	16	1	9,778	131,420	60,832	1,539,003	
4	April	28	19	29,677	45,408	220,302	441,051	
5	May	22	1	58,924	34,660	1,210,280	94,203	
6	June	25	8	73,843	2,016	1,852,782	4,967	
7	July	30	18	80,259	6,470	2,281,228	50,327	
8	August	13	17	79,793	4,606	2,322,058	9,346	
9	September	4	9	93,334	352	2,505,621	1,819	
10	October	5	22	84,185	10,688	1,535,996	137,593	
11	November	14	19	14,815	119,033	131,590	1,393,912	
12	December	7	5	1,965	120,705	11,475	2,066,716	
13	**TOTAL**					12,164,342	11,416,072	

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

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 33

SOURCES OF GAS SUPPLY

Year: 2011

	Name of Supplier 1/	Last Year Volumes Dkt	This Year Volumes Dkt	Last Year Avg. Commodity Cost	This Year Avg. Commodity Cost
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29	1/ Supplier information is proprietary and confidential.				
30					
31					
32					
33	**Total Gas Supply Volumes**	34,246,581	36,349,510	$4.043	$3.803

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 34

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2011

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings **(Mcf or Dkt)**	Achieved Savings **(Mcf or Dkt)**	Difference
1							
2	MT Conservation & DSM Program	$98,929	$92,470	6.98%	N/A	5,912	N/A
3	(As Detailed on Schedule 36B)						
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32	**TOTAL**	$98,929	$92,470	6.98%	N/A	5,912	N/A

MONTANA CONSUMPTION AND REVENUES

Year: 2011

	Sales of Gas	Operating Revenues		DK Sold		Avg. No. of Customers	
		Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1	Residential	$45,522,909	$43,725,041	6,268,127	5,936,058	69,976	69,403
2	Firm General	26,717,946	25,349,139	3,814,965	3,579,825	8,558	8,474
3	Small Interruptible	1,382,090	1,024,066	278,444	196,222	9	7
4	Large Interruptible	107,192	1,161	23,609	146	0	0
5							
6							
7							
8							
9							
10							
11	**TOTAL**	$73,730,137	$70,099,407	10,385,145	9,712,251	78,543	77,884
12							
13							
14		**Operating Revenues**		**BCF Transported**		**Avg. No. of Customers**	
15							
16							
17	**Transportation of Gas**	Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
18							
19	Small Interruptible	$619,197	$621,303	0.7	0.7	35	36
20	Large Interruptible	647,477	651,301	4.6	4.3	5	5
21							
22							
23							
24	**TOTAL**	$1,266,674	$1,272,604	5.3	5.0	40	41

NATURAL GAS UNIVERSAL SYSTEM BENEFITS PROGRAMS

Year: 2011

	Program Description	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (Mcf or Dkt)	Most recent program evaluation
1	Local Conservation					
2						
3						
4						
5						
6						
7						
8	Market Transformation					
9						
10						
11						
12						
13						
14						
15	Research & Development					
16						
17						
18						
19						
20						
21						
22	Low Income					
23	Discounts	$695,110	$0	$695,110		2011
24	Furnace Safety/Repair	100,000	0	100,000		2011
25	Bill Assistance	130,000	0	130,000		2011
26						
27						
28						
29	Other					
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42	Total	$925,110	$0	$925,110		2011

43	Number of customers that received low income rate discounts	(Average)	4,675
44	Average monthly bill discount amount ($/mo)		$12.40
45	Average LIEAP-eligible household income		N/A
46	Number of customers that received weatherization assistance		N/A
47	Expected average annual bill savings from weatherization		N/A
48	Number of residential audits performed		N/A

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

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS Year: 2011

	Program Description	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (Mcf or Dkt)	Most recent program evaluation
1	Local Conservation					
2	High Efficiency Furnace	$90,499	$0	$90,499	4,931	2011
3						
4	Programmable Thermostat	8,430	0	8,430	981	2011
5						
6						
7						
8						
9	Demand Response					
10						
11						
12						
13						
14						
15						
16	Market Transformation					
17						
18						
19						
20						
21						
22						
23	Research & Development					
24						
25						
26						
27						
28						
29						
30	Low Income					
31						
32						
33						
34						
35						
36	Other					
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Total	$98,929	$0	$98,929	5,912	2011

Response No. MCC-092
Attachment C

MONTANA-DAKOTA UTILITIES CO.
INCOME STATEMENT
GAS UTILITY - MONTANA
TWELVE MONTHS ENDED DECEMBER 31, 2011

	Total Company	Montana	Other	Reference
Operating Revenues				
Sales	$242,315,494	$72,489,259	$169,826,235	Rule 38.5.164
Transportation	3,731,261	1,252,889	2,478,372	Rule 38.5.164
Other	1,630,614	368,826	1,261,788	Rule 38.5.164
Total Revenues	247,677,369	74,110,974	173,566,395	
Operating Expenses				
Operation and Maintenance				
Cost of Gas	179,121,296	52,735,031	126,386,265	Rule 38.5.157
Other O&M	38,564,254	10,869,311	27,694,943	Rule 38.5.157
Total O&M	217,685,550	63,604,342	154,081,208	
Depreciation	9,814,146	3,011,298	6,802,848	Rule 38.5.165
Taxes Other Than Income	6,138,074	3,308,019	2,830,055	Rule 38.5.173
Current Income Taxes	(11,756,557)	(2,930,186)	(8,826,371)	Rule 38.5.169
Deferred Income Taxes	13,390,065	3,489,201	9,900,864	Rule 38.5.169
Total Expenses	235,271,278	70,482,674	164,788,604	
Operating Income	$12,406,091	$3,628,300	$8,777,791	
Rate Base	$134,025,220	$43,247,498	$90,777,722	
Rate of Return	9.257%	8.390%	9.670%	

MONTANA-DAKOTA UTILITIES CO.
AVERAGE RATE BASE
GAS UTILITY - MONTANA
TWELVE MONTHS ENDED DECEMBER 31, 2011

	Total Company	Montana	Other	Reference
Gas Plant in Service	$322,437,954	$94,105,839	$228,332,115	Rule 38.5.123
Accumulated Reserve for Depreciation	174,081,879	51,259,183	122,822,696	Rule 38.5.133
Net Gas Plant in Service	148,356,075	42,846,656	105,509,419	
CWIP in Service Pending Reclassification	2,807,343	500,474	2,306,869	Rule 38.5.123
Total Gas Plant in Service	151,163,418	43,347,130	107,816,288	
Additions				
Materials and Supplies	2,005,951	533,337	1,472,614	Rule 38.5.141
Fuel Stocks	22,844	0	22,844	Rule 38.5.141
Gas in Underground Storage	7,134,766	7,134,766	0	Rule 38.5.141
Prepayments	1,237,614	1,175,889	61,725	Rule 38.5.141
Loss on Debt	1,956,550	584,820	1,371,730	Rule 38.5.141
Other	152,688	128,892	23,796	Rule 38.5.141
Total Additions	12,510,413	9,557,704	2,952,709	
Total Before Deductions	$163,673,831	$52,904,834	$110,768,997	
Deductions				
Accumulated Deferred Income Taxes	24,948,195	8,925,996	16,022,199	Rule 38.5.169
Accumulated Investment Tax Credits	11,925	4,084	7,841	Rule 38.5.169
Customer Advances	4,688,491	727,256	3,961,235	Rule 38.5.141
Total Deductions	29,648,611	9,657,336	19,991,275	
Total Rate Base	$134,025,220	$43,247,498	$90,777,722	

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF PRO FORMA ADJUSTMENTS
GAS UTILITY - MONTANA

	Adjustment No.	Pro Forma Adjustment	Reference	
Revenue				
Current rates	1	($13,609,329)	Rule 38.5.164	Statement H, page 3
Normal Weather	2	(1,467,031)	Rule 38.5.164	Statement H, page 4
Annualized volumes	3	257,226	Rule 38.5.164	Statement H, page 5
Other Revenue	4	47,286	Rule 38.5.164	Statement H, page 6
Total adjustments to Revenue		($14,771,848)		
Expenses				
Cost of Gas	5	($13,880,459)	Rule 38.5.157	Statement G, page 3
Other O&M				
Labor	6	$269,722	Rule 38.5.157	Statement G, page 4
Benefits	7	(75,501)	Rule 38.5.157	Statement G, page 5
Vehicles & Work Equipment	8	(6,716)	Rule 38.5.157	Statement G, page 6
Company Consumption	9	(8,120)	Rule 38.5.157	Statement G, page 7
Uncollectible Accounts	10	(14,963)	Rule 38.5.157	Statement G, page 8
Advertising	11	(31,656)	Rule 38.5.157	Statement G, page 9
Insurance	12	13,839	Rule 38.5.157	Statement G, page 10
Industry Dues	13	(7,138)	Rule 38.5.157	Statement G, page 11
Regulatory Commission Expense	14	108,300	Rule 38.5.157	Statement G, page 12
Total adjustments to Other O&M		247,767		
Depreciation Expense	15	1,412,304	Rule 38.5.165	Statement I, page 1
Taxes Other than Income				
Ad Valorem	16	114,387	Rule 38.5.174	Statement K, page 1
Payroll Taxes	17	20,322	Rule 38.5.174	Statement K, page 3
MCC and PSC Taxes	18	(167,229)	Rule 38.5.174	Statement K, page 4
Total adj. to Taxes Other than Income		(32,520)		
Current Income Taxes				
Interest Annualization	19	(51,878)	Rule 38.5.169	Statement J, page 8
Tax Depreciation on Plant Additions	20	2,817,177	Rule 38.5.169	Statement J, page 9
Other Tax Deductions	21	(400,022)	Rule 38.5.169	Statement J, page 10
Income Taxes on Pro Forma Adj.	22	(1,923,771)	Rule 38.5.169	Statement J, page 11
Elimination of Closing/Filing and Prior Period	23	1,560,882	Rule 38.5.169	Statement J, page 12
Total adj. to Current Income Taxes		(362,889)		
Deferred Income Taxes				
Plant Additions	20	1,109,616	Rule 38.5.169	Statement J, page 9
Elimination of Closing/Filing and Prior Period	23	(1,302,970)	Rule 38.5.169	Statement J, page 12
Other Tax Deductions	21	38,579	Rule 38.5.169	Statement J, page 10
Total adj. to Deferred Income Taxes		(154,775)		
Total Expenses		(12,770,572)		
Net Adjustments to Operating Income		($2,001,276)		

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
SUMMARY OF PRO FORMA RATE BASE ADJUSTMENTS

Plant	Adjustment	Amount	Reference	
Plant Additions	A	$6,357,622	Rule 38.5.123	Statement C Page 2
Accumulated Reserve				
Plant Additions	B	3,202,646	Rule 38.5.133	Statement D Page 2
Adjustments to Net Plant		3,154,976		
Additions:				
Materials and Supplies	C	99,695	Rule 38.5.143	Statement E Page 1
Gas in Underground Storage	D	(855,502)	Rule 38.5.143	Statement E Page 2
Prepaid Insurance	E	93,808	Rule 38.5.143	Statement E Page 3
Prepaid Demand and Commodity	F	(642,915)	Rule 38.5.143	Statement E Page 4
Unamortized Loss on Debt	G	(53,806)	Rule 38.5.143	Statement E Page 5
Provision for Pensions & Benefits	H	1,268,837	Rule 38.5.143	Statement E Page 6
Provision for Injuries & Damages	I	(109,736)	Rule 38.5.143	Statement E Page 7
Deferred FAS 106 Costs	J	273,775	Rule 38.5.143	Statement E Page 8
Total Additions		74,156		
Deductions:				
Accumulated Def. Inc. Tax				
Plant Additions	K	1,887,637	Rule 38.5.169	Statement J Page 17
Normalization	L	(25,349)	Rule 38.5.169	Statement J Page 17
Deferred FAS 106 Costs	J	105,855	Rule 38.5.169	Statement J Page 17
Unamortized Loss on Debt	G	(31,526)	Rule 38.5.169	Statement J Page 17
Pensions & Benefits	H	846,179	Rule 38.5.169	Statement J Page 17
Injuries and Damages	I	(41,583)	Rule 38.5.169	Statement J Page 17
Investment Tax Credits	M	(3,488)	Rule 38.5.169	Statement J Page 17
Customer Advances for Construction	N	(20,926)	Rule 38.5.143	Statement E Page 9
Total Deductions		2,716,799		
Total Pro Forma Adjustments		$512,333		

MONTANA-DAKOTA UTILITIES CO.
PRO FORMA INCOME STATEMENT
GAS UTILITY - MONTANA
TWELVE MONTHS ENDED DECEMBER 31, 2011

	Per Books	Pro Forma Adjustments	Total Adjusted Amount
Operating Revenues			
Sales	$72,489,259	($14,697,778)	$57,791,481
Transportation	1,252,889	(121,356)	1,131,533
Other	368,826	47,286	416,112
Total Revenues	74,110,974	(14,771,848)	59,339,126
Operating Expenses			
Operation and Maintenance			
Cost of Gas	52,735,031	(13,880,459)	38,854,572
Other O&M	10,869,311	247,767	11,117,078
Total O&M	63,604,342	(13,632,692)	49,971,650
Depreciation	3,011,298	1,412,304	4,423,602
Taxes Other Than Income	3,308,019	(32,520)	3,275,499
Current Income Taxes	(2,930,186)	(362,889)	(3,293,075)
Deferred Income Taxes	3,489,201	(154,775)	3,334,426
Total Expenses	70,482,674	(12,770,572)	57,712,102
Operating Income	$3,628,300	($2,001,276)	$1,627,024
Rate Base	$43,247,498	$512,333	$43,759,831
Rate of Return	8.390%		3.718%

MONTANA-DAKOTA UTILITIES CO.
AVERAGE RATE BASE
GAS UTILITY - MONTANA
TWELVE MONTHS ENDED DECEMBER 31, 2011
PRO FORMA

	Average Balance @ 12/31/11	Pro Forma Adjustments	Pro Forma
Gas Plant in Service	$94,105,839	$6,357,622	$100,463,461
Accumulated Reserve for Depreciation	51,259,183	3,202,646	54,461,829
Net Gas Plant in Service	42,846,656	3,154,976	46,001,632
CWIP in Service Pending Reclassification	500,474		500,474
Total Gas Plant in Service	43,347,130	3,154,976	46,502,106
Additions			
Materials and Supplies	533,337	99,695	633,032
Gas in Underground Storage	7,134,766	(855,502)	6,279,264
Prepayments	1,175,889	(549,107)	626,782
Unamortized Gain (Loss) on Debt	584,820	(53,806)	531,014
Provision for Pensions & Benefits		1,268,837	1,268,837
Provision for Injuries & Damages		(109,736)	(109,736)
Deferred FAS 106 Costs	128,892	273,775	402,667
Total Additions	9,557,704	74,156	9,631,860
Total Before Deductions	$52,904,834	$3,229,132	$56,133,966
Deductions			
Accumulated Deferred Income Taxes	8,925,996	2,741,213	11,667,209
Accumulated Investment Tax Credits	4,084	(3,488)	596
Customer Advances	727,256	(20,926)	706,330
Total Deductions	9,657,336	2,716,799	12,374,135
Total Rate Base	$43,247,498	$512,333	$43,759,831

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF PRO FORMA ADJUSTMENTS
GAS UTILITY - MONTANA
MONTANA-DAKOTA UTILITIES CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
GAS UTILITY - MONTANA

	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**	Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	$57,791,481	**$3,455,478**	$61,246,959
Transportation	1,131,533		1,131,533
Other	416,112		416,112
Total Revenues	59,339,126	3,455,478	62,794,604
Operating Expenses			
Operation and Maintenance			
Cost of Gas	38,854,572		38,854,572
Other O&M	11,117,078		11,117,078
Total O&M	49,971,650		49,971,650
Depreciation	4,423,602		4,423,602
Taxes Other Than Income	3,275,499	11,058 2/	3,286,557
Current Income Taxes	(3,293,075)	1,356,672 2/	(1,936,403)
Deferred Income Taxes	3,334,426		3,334,426
Total Expenses	57,712,102	1,367,730	59,079,832
Operating Income	$1,627,024	$2,087,748	$3,714,772
Rate Base	$43,759,831		$43,759,831
Rate of Return	**3.718%**		**8.489%**

1/ See Rule 38.5.175, page 6.
2/ Reflects taxes at 39.3875% after deducting Consumer Counsel tax of .12% and PSC tax of .20%.

Response No. MCC-092
Attachment D

Credit Ratings

AGL Resources Inc. (NYSE: GAS)

Credit Ratings

	Moody's	S&P	Fitch Ratings
Long-term Rating	(P)Baa1	BBB+	BBB+
Outlook	Stable	Stable	Stable
Watch	-	-	-
As of Date	12/1/2005	12/15/2011	12/3/2012
	(P)Baa1 SNL Start *1/2/2002*	A- (WN) Affirm *12/7/2010*	A- (OS) Affirm *12/7/2011*
	-	A- (OS) Affirm *12/12/2007*	A- (OS) Affirm *12/7/2010*
	-	A- (ON) Affirm *12/8/2004*	A- (OS) Affirm *8/19/2010*
	-	A- (WN) Affirm *7/16/2004*	A- (OS) Affirm *8/4/2009*
	-	A- Affirm *6/27/2003*	A- (OS) Affirm *7/10/2008*

Comparison with Peers : Moody's - SNL Default Peer Group

Company Name	Long-term Rating	Outlook	Watch	As of Date
AGL Resources Inc.	(P)Baa1	Stable	-	12/1/2005
Southwest Gas Corp.	Baa1	Stable	-	3/15/2012
Atmos Energy Corp.	Baa1	Stable	-	5/11/2011
Questar Corp.	A3	Stable	-	12/7/2010
Northwest Natural Gas Co.	(P)A3	Stable	-	12/15/2008
ONEOK Inc.	Baa2	Stable	-	10/5/2005
National Fuel Gas Co.	Baa1	Stable	-	4/28/2005
Piedmont Natural Gas Co. Inc.	A3	Stable	-	4/28/2004
Laclede Group Inc.	(P)Baa2	Stable	-	11/15/2003

Credit Ratings Details

	Moody's	S&P	Fitch Ratings
Long-term Issuer	-	BBB+ (OS) Downgrade *12/15/2011*	BBB+ (OS) Downgrade *12/3/2012*
	-	A- (WN) Affirm *12/7/2010*	A- (OS) Affirm *12/7/2011*
	-	A- (OS) Affirm *12/12/2007*	A- (OS) Affirm *12/7/2010*
	-	A- (ON) Affirm *12/8/2004*	A- (OS) Affirm *8/19/2010*
	-	A- (WN) Affirm *7/16/2004*	A- (OS) Affirm *8/4/2009*
	-	A-	A- (OS)

		Affirm *6/27/2003*	Affirm *7/10/2008*
Senior Unsecured	(P)Baa1 (OS) Affirm *12/1/2005*	-	-
	(P)Baa1 Initiate *1/2/2002*	-	-
Short-term/Commercial Paper	-	A-2 Affirm *12/12/2007*	Remove *7/10/2007*
	-	A-2 (WR) Affirm *12/8/2004*	F2 Affirm *4/13/2006*
	-	A-2 (WN) Affirm *7/16/2004*	F2 Affirm *12/6/2005*
	-	A-2 SNL Start *6/27/2003*	F2 Affirm *11/22/2004*
	-	-	F2 Affirm *2/11/2003*
	-	-	F2 SNL Start
Subordinated Debt	Baa2 Affirm *12/1/2005*	-	-
	Baa2 SNL Start *9/21/2000*	-	-
Trust Preferred	Remove *7/20/2007*	Remove *7/31/2007*	Remove *7/31/2007*
	Baa2 Affirm *12/1/2005*	BBB (WR) Affirm *12/8/2004*	BBB+ Affirm *7/10/2007*
	Baa2 Affirm *7/15/2004*	BBB (WN) Affirm *7/16/2004*	BBB+ Affirm *4/13/2006*
	Baa2 SNL Start	BBB Affirm *6/27/2003*	BBB+ Affirm *12/6/2005*
	-	BBB SNL Start	BBB+ (WR) Affirm *11/22/2004*
	-	-	BBB+ (WN) Affirm *7/15/2004*

Subsidiary Credit Ratings Details

	Moody's	S&P	Fitch Ratings	AM Best*
AGL Capital Corp.				
Long-term Rating	Baa2 (OS) Affirm *12/1/2005*	-	BBB+ (OS) Downgrade *12/3/2012*	No SNL Coverage
	Baa2 SNL Start *5/3/2001*	-	A- (OS) Affirm *12/7/2011*	No SNL Coverage

	-	-	A- (OS) Affirm *12/7/2010*	No SNL Coverage
	-	-	A- (OS) Affirm *8/19/2010*	No SNL Coverage
	-	-	A- (OS) Affirm *8/4/2009*	No SNL Coverage
	-	-	A- (OS) Affirm *7/10/2008*	No SNL Coverage
Senior Unsecured	Remove *1/14/2011*	BBB+ (WR) Affirm *12/15/2011*	BBB+ Downgrade *12/3/2012*	No SNL Coverage
	Baa1 (OS) Affirm *12/1/2005*	BBB+ (WN) Affirm *12/7/2010*	A- Affirm *12/7/2011*	No SNL Coverage
	Baa1 Affirm *2/16/2001*	BBB+ (OS) Affirm *12/12/2007*	A- Affirm *12/7/2010*	No SNL Coverage
	Baa1 SNL Start	BBB+ SNL Start	A- Affirm *7/10/2007*	No SNL Coverage
	-	-	A- SNL Start	No SNL Coverage
Short-term/Commercial Paper	P-2 Affirm *12/1/2005*	A-2 SNL Start *9/22/2000*	F2 Affirm *12/3/2012*	No SNL Coverage
	P-2 Affirm *9/21/2000*	-	F2 Affirm *12/7/2011*	No SNL Coverage
	P-2 SNL Start	-	F2 Affirm *12/7/2010*	No SNL Coverage
	-	-	F2 Affirm *8/19/2010*	No SNL Coverage
	-	-	F2 Affirm *8/4/2009*	No SNL Coverage
	-	-	F2 Affirm *7/10/2008*	No SNL Coverage
Subordinated Debt	Baa2 (OS) Affirm *12/1/2005*	-	-	No SNL Coverage
	Baa2 SNL Start *5/3/2001*	-	-	No SNL Coverage
Atlanta Gas Light Co.				
Long-term Rating	A3 (OS) Affirm *12/1/2005*	BBB+ (OS) Downgrade *12/15/2011*	BBB+ (OS) Downgrade *12/3/2012*	No SNL Coverage
	A3 SNL Start *9/21/2000*	A- (WN) Affirm *12/7/2010*	A- (OS) Affirm *12/7/2011*	No SNL Coverage

	-	A- (OS) Affirm *12/12/2007*	A- (OS) Affirm *12/7/2010*	No SNL Coverage
	-	A- (ON) Affirm *12/8/2004*	A- (OS) Affirm *8/19/2010*	No SNL Coverage
	-	A- (WN) Affirm *7/16/2004*	A- (OS) Affirm *8/4/2009*	No SNL Coverage
	-	A- Affirm *6/27/2003*	A- (OS) Affirm *7/10/2008*	No SNL Coverage
Senior Unsecured	A3 (OS) Affirm *12/1/2005*	BBB+ (WR) Downgrade *12/15/2011*	A- Downgrade *12/3/2012*	No SNL Coverage
	A3 SNL Start *9/21/2000*	A- (WN) Affirm *12/7/2010*	A Affirm *12/7/2011*	No SNL Coverage
	-	A- SNL Start *4/25/2005*	A Affirm *12/7/2010*	No SNL Coverage
	-	-	A Affirm *7/10/2007*	No SNL Coverage
	-	-	A SNL Start	No SNL Coverage
Northern Illinois Gas Co.				
Long-term Rating	A3 (OS) Downgrade *12/13/2011*	BBB+ (OS) Downgrade *12/15/2011*	A (OS) Affirm *12/3/2012*	No SNL Coverage
	A2 (ON) Affirm *12/7/2010*	AA (WN) Affirm *12/7/2010*	A (OS) Affirm *12/7/2011*	No SNL Coverage
	A2 (OS) Downgrade *7/21/2006*	AA (OS) Affirm *4/14/2008*	A (OS) Affirm *12/7/2010*	No SNL Coverage
	A1 (WN) Affirm *4/27/2006*	AA (ON) Affirm *12/8/2004*	A (OS) Affirm *10/4/2010*	No SNL Coverage
	A1 (WR) Downgrade *4/25/2003*	AA (ON) Affirm *4/15/2003*	A (OS) Affirm *9/8/2009*	No SNL Coverage
	Aa2 (WN) Affirm *7/24/2002*	AA (WN) Affirm *7/22/2002*	A (OS) Affirm *7/24/2008*	No SNL Coverage
Senior Unsecured	-	BBB+ (WR) Downgrade *12/15/2011*	A+ Affirm *12/3/2012*	No SNL Coverage
	-	AA (WN) Affirm *12/7/2010*	A+ Affirm *12/7/2011*	No SNL Coverage
	-	AA SNL Start *11/7/2008*	A+ Affirm *12/7/2010*	No SNL Coverage
	-	-	A+ SNL Start *7/28/2007*	No SNL Coverage
	P-2	A-2 (WR)	F1	No SNL Coverage

AGL Resources Inc. (NYSE: GAS)

Short-term/Commercial Paper	Downgrade *12/13/2011*	Downgrade *12/15/2011*	Affirm *12/3/2012*	
	P-1 Affirm *7/21/2006*	A-1+ (WN) Affirm *12/7/2010*	F1 Affirm *12/7/2011*	No SNL Coverage
	P-1 (WR) Affirm *4/25/2003*	A-1+ Affirm *4/14/2008*	F1 Affirm *12/7/2010*	No SNL Coverage
	P-1 (WN) Affirm *7/24/2002*	A-1+ Affirm *4/15/2003*	F1 Affirm *10/4/2010*	No SNL Coverage
	P-1 Affirm *7/26/1974*	A-1+ Affirm *7/22/2002*	F1 Affirm *9/8/2009*	No SNL Coverage
	P-1 SNL Start	A-1+ SNL Start *11/23/1981*	F1 Affirm *7/24/2008*	No SNL Coverage
Senior Secured Debt	A1 Downgrade *12/13/2011*	A (WR) Downgrade *12/15/2011*	AA- Affirm *12/3/2012*	No SNL Coverage
	Aa3 Upgrade *8/3/2009*	AA (WN) Affirm *12/7/2010*	AA- Affirm *12/7/2011*	No SNL Coverage
	A1 (WR) Downgrade *7/21/2006*	AA Affirm *4/14/2008*	AA- Affirm *12/7/2010*	No SNL Coverage
	Aa3 (WN) Affirm *4/27/2006*	AA (WR) Affirm *4/15/2003*	AA- Affirm *7/5/2006*	No SNL Coverage
	Aa3 (WR) Downgrade *4/25/2003*	AA (WN) SNL Start	AA- Affirm *7/1/2005*	No SNL Coverage
	Aa1 (WN) Affirm *7/24/2002*	-	AA- Downgrade *6/29/2004*	No SNL Coverage
NUI Corp.				
Long-term Rating	WR Remove *11/22/2004*	-	-	No SNL Coverage
	Caa1 (OD) Affirm *7/15/2004*	-	-	No SNL Coverage
	Caa1 Downgrade *4/6/2004*	-	-	No SNL Coverage
	B3 (WR) Downgrade *10/6/2003*	-	-	No SNL Coverage
	B1 (WU) Affirm *9/26/2003*	-	-	No SNL Coverage
	B1 (WR) Downgrade *5/7/2003*	-	-	No SNL Coverage
Pivotal Utility Holdings Inc.				
Long-term Rating	Remove *2/25/2005*	BBB+ (OS) Downgrade *12/15/2011*	-	No SNL Coverage

	Baa1 Upgrade *11/30/2004*	A- (WN) Affirm *12/7/2010*	-	No SNL Coverage
	B1 Affirm *7/15/2004*	A- (OS) Affirm *12/12/2007*	-	No SNL Coverage
	B1 Downgrade *4/6/2004*	A- Upgrade *12/8/2004*	-	No SNL Coverage
	Ba3 (WR) Downgrade *10/6/2003*	BB (WU) Downgrade *11/21/2003*	-	No SNL Coverage
	Ba1 (WU) Affirm *9/26/2003*	BBB- (WU) Downgrade *9/26/2003*	-	No SNL Coverage
Senior Unsecured	-	Remove *11/13/2009*	-	No SNL Coverage
	-	A- (OS) Affirm *12/12/2007*	-	No SNL Coverage
	-	A- SNL Start	-	No SNL Coverage
Seven Seas Insurance Co. Inc.				
Financial Strength	-	-	-	A Affirm *2/28/2012*
	-	-	-	A Affirm *2/17/2011*
	-	-	-	A Affirm *12/22/2009*
	-	-	-	A Affirm *12/19/2008*
	-	-	-	A *2/6/2008*

Ratings News

Fitch downgrades ratings for AGL, Atlanta Gas, affirms Nicor Gas 12/3/2012 3:49 PM ET

Fitch Ratings has downgraded the long-term issuer default ratings of AGL Resources Inc., AGL Capital Corp. and Atlanta Gas Light Co. to BBB+ from A-. Northern Illinois Gas Co.'s long-term IDR was affirmed at A.

A.M. Best affirms Seven Seas Insurance ratings 2/28/2012 7:16 PM ET

A.M. Best affirmed Seven Seas Insurance's financial strength rating and issuer credit rating.

S&P rates newly merged AGL/Nicor at BBB+ 12/16/2011 1:50 PM ET

An increase in financial leverage caused Standard and Poor's to reduce AGL Resources Inc.'s rating following the closed merger with Nicor Inc.

Moody's report finds rationale for further utility M&A 'compelling' 11/9/2011 5:28 PM ET

Why have the most recent round of electric and gas utility mergers in the U.S. been more successful than in the period following the passage of the 2005 U.S. Energy Policy Act? A Nov. 4 report by Moody's posits some answers, identifying an emphasis on credit quality as a key factor.

Ratings Watch Action Legend: (WP) Watch Positive, (WN) Watch Negative, (WU) Watch Uncertain, (WR) Watch Removed, (OP) Outlook Positive, (ON) Outlook Negative, (OS) Outlook Stable, (OD) Outlook Developing.

AGL Resources Inc. (NYSE: GAS)

* AM Best Ratings (Financial Strength Ratings) are solely sourced from information available in the public domain. SNL does not provide coverage of AM Best Credit Ratings.

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Credit Ratings

Atmos Energy Corporation (NYSE: ATO)

Credit Ratings

	Moody's	S&P	Fitch Ratings
Long-term Rating	Baa1	BBB+	BBB+
Outlook	Stable	Stable	Stable
Watch	-	-	-
As of Date	5/11/2011	12/23/2008	4/30/2012
	Baa2 (WP) Affirm *3/31/2011*	BBB (OP) Affirm *6/11/2007*	BBB+ (OS) Upgrade *6/2/2011*
	Baa2 (OP) Affirm *3/19/2010*	BBB (OS) Affirm *12/22/2005*	BBB (OP) Affirm *6/21/2010*
	Baa2 Upgrade *5/18/2009*	BBB Downgrade *9/30/2004*	BBB (OS) Affirm *3/23/2009*
	Baa3 (WP) Affirm *3/23/2009*	A- (WN) Affirm *6/17/2004*	BBB (OS) Affirm *8/7/2008*
	Baa3 (OP) Affirm *1/8/2009*	A- Affirm *1/10/2003*	BBB (OS) Affirm *6/7/2007*

Comparison with Peers : Moody's - SNL Default Peer Group

Company Name	Long-term Rating	Outlook	Watch	As of Date
Atmos Energy Corp.	Baa1	Stable	-	5/11/2011
Southwest Gas Corp.	Baa1	Stable	-	3/15/2012
Questar Corp.	A3	Stable	-	12/7/2010
Northwest Natural Gas Co.	(P)A3	Stable	-	12/15/2008
Energen Corp.	Baa3	Stable	-	9/24/2007
National Fuel Gas Co.	Baa1	Stable	-	4/28/2005
Piedmont Natural Gas Co. Inc.	A3	Stable	-	4/28/2004
Laclede Group Inc.	(P)Baa2	Stable	-	11/15/2003

Credit Ratings Details

	Moody's	S&P	Fitch Ratings
Long-term Issuer	-	BBB+ (OS) Upgrade *12/23/2008*	BBB+ (OS) Affirm *4/30/2012*
	-	BBB (OP) Affirm *6/11/2007*	BBB+ (OS) Upgrade *6/2/2011*
	-	BBB (OS) Affirm *12/22/2005*	BBB (OP) Affirm *6/21/2010*
	-	BBB Downgrade *9/30/2004*	BBB (OS) Affirm *3/23/2009*
	-	A- (WN) Affirm *6/17/2004*	BBB (OS) Affirm *8/7/2008*
	-	A- Affirm *1/10/2003*	BBB (OS) Affirm *6/7/2007*

Atmos Energy Corporation (NYSE: ATO)

Senior Unsecured	Baa1 (OS) Upgrade *5/11/2011*	BBB+ Upgrade *12/23/2008*	A- Affirm *4/30/2012*
	Baa2 (WP) Affirm *3/31/2011*	BBB Affirm *6/11/2007*	A- Upgrade *6/2/2011*
	Baa2 (OP) Affirm *3/19/2010*	BBB Affirm *12/22/2005*	BBB+ Affirm *6/7/2007*
	Baa2 Upgrade *5/18/2009*	BBB (WR) Downgrade *9/30/2004*	BBB+ Affirm *1/13/2006*
	Baa3 (WP) Affirm *3/23/2009*	A- SNL Start	BBB+ (WR) Downgrade *9/30/2004*
	Baa3 (OP) Affirm *1/8/2009*	-	A- (WN) SNL Start
Short-term/Commercial Paper	P-2 (WR) Affirm *5/11/2011*	A-2 Affirm *6/11/2007*	F2 Affirm *4/30/2012*
	P-2 (WP) Affirm *3/31/2011*	A-2 (WR) Affirm *9/30/2004*	F2 Affirm *6/2/2011*
	P-2 Upgrade *5/18/2009*	A-2 (WN) Affirm *6/17/2004*	F2 Affirm *6/21/2010*
	P-3 (WP) Affirm *3/23/2009*	A-2 Affirm *1/10/2003*	F2 Affirm *3/23/2009*
	P-3 Downgrade *9/29/2004*	A-2 Affirm *10/16/1998*	F2 Affirm *8/7/2008*
	P-2 (WN) Affirm *6/17/2004*	A-2 SNL Start	F2 Affirm *6/7/2007*
Senior Secured Debt	-	Remove *8/20/2008*	Remove *1/13/2006*
	-	A- Affirm *6/11/2007*	BBB+ (WR) Downgrade *9/30/2004*
	-	A- Upgrade *12/22/2005*	A- (WN) Affirm *6/17/2004*
	-	BBB (WR) Downgrade *9/30/2004*	A- Affirm *2/27/2004*
	-	A- (WN) Affirm *6/17/2004*	A- SNL Start
	-	A- Affirm *1/10/2003*	-

Ratings News

Fitch upgrades Atmos Energy's ratings	6/3/2011 11:54 AM ET

Atmos Energy Corporation (NYSE: ATO)

The rating outlook is stable.

Moody's upgrades ratings for Atmos Energy 5/12/2011 12:42 PM ET

The rating agency also changed the rating outlook for Atmos Energy to stable from rating under review.

Ratings Watch Action Legend: (WP) Watch Positive, (WN) Watch Negative, (WU) Watch Uncertain, (WR) Watch Removed, (OP) Outlook Positive, (ON) Outlook Negative, (OS) Outlook Stable, (OD) Outlook Developing.

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Credit Ratings

Laclede Group, Inc. (The) (NYSE: LG)

Credit Ratings

	Moody's	S&P	Fitch Ratings
Long-term Rating	(P)Baa2	A	A-
Outlook	Stable	Stable	Stable
Watch	-	-	-
As of Date	11/15/2003	3/26/2008	12/13/2011
	(P)Baa2 SNL Start *8/6/2002*	A (OS) Downgrade *5/5/2003*	A- (OS) Affirm *12/17/2010*
	-	A+ SNL Start *4/24/2002*	A- (OS) Affirm *12/18/2009*
	-	-	A- (OS) Affirm *11/10/2008*
	-	-	A- (OS) Affirm *6/20/2007*
	-	-	A- (OS) Affirm *6/6/2006*

Comparison with Peers : Moody's - SNL Default Peer Group

Company Name	Long-term Rating	Outlook	Watch	As of Date
Laclede Group Inc.	(P)Baa2	Stable	-	11/15/2003
EQT Corp.	Baa2	Negative	-	11/2/2011
Northwest Natural Gas Co.	(P)A3	Stable	-	12/15/2008
Energen Corp.	Baa3	Stable	-	9/24/2007
National Fuel Gas Co.	Baa1	Stable	-	4/28/2005

Credit Ratings Details

	Moody's	S&P	Fitch Ratings
Long-term Issuer	-	A (OS) Affirm *3/26/2008*	A- (OS) Affirm *12/13/2011*
	-	A (OS) Downgrade *5/5/2003*	A- (OS) Affirm *12/17/2010*
	-	A+ SNL Start *4/24/2002*	A- (OS) Affirm *12/18/2009*
	-	-	A- (OS) Affirm *11/10/2008*
	-	-	A- (OS) Affirm *6/20/2007*
	-	-	A- (OS) Affirm *6/6/2006*
Senior Unsecured	(P)Baa2 (OS) Affirm *11/15/2003*	-	-

	(P)Baa2 Initiate *8/6/2002*	-	-
Trust Preferred	-	-	BBB+ Affirm *6/20/2007*
	-	-	BBB+ Affirm *6/6/2006*
	-	-	BBB+ SNL Start *12/9/2002*

Subsidiary Credit Ratings Details

	Moody's	S&P	Fitch Ratings
Laclede Gas Co.			
Long-term Rating	(P)Baa1 (OS) Affirm *11/15/2003*	A (OS) Downgrade *5/5/2003*	A- (OS) Affirm *12/13/2011*
	(P)Baa1 SNL Start *8/6/2002*	A+ (WR) Downgrade *4/24/2002*	A- (OS) Affirm *12/17/2010*
	-	AA- (WN) SNL Start	A- (OS) Affirm *12/18/2009*
	-	-	A- (OS) Downgrade *11/10/2008*
	-	-	A (OS) Affirm *6/20/2007*
	-	-	A (OS) Affirm *6/6/2006*
Senior Unsecured	(P)Baa1 (OS) Affirm *11/15/2003*	-	-
	(P)Baa1 Initiate *8/6/2002*	-	-
Short-term/Commercial Paper	P-2 Downgrade *8/6/2002*	A-1 Downgrade *4/24/2002*	F1 Affirm *12/13/2011*
	P-1 Affirm *5/2/2002*	A-1+ (WN) SNL Start	F1 Affirm *12/17/2010*
	P-1 SNL Start	-	F1 Affirm *12/18/2009*
	-	-	F1 SNL Start *11/10/2008*
Senior Secured Debt	A2 Upgrade *8/3/2009*	A Downgrade *5/5/2003*	A+ Affirm *12/13/2011*
	A3 Downgrade *8/6/2002*	A+ Downgrade *4/24/2002*	A+ Affirm *12/17/2010*

	A1 SNL Start	AA- SNL Start	A+ Affirm *6/20/2007*
	-	-	A+ Affirm *6/6/2006*
	-	-	A+ Affirm *6/4/2004*
	-	-	A+ SNL Start

Ratings Watch Action Legend: (WP) Watch Positive, (WN) Watch Negative, (WU) Watch Uncertain, (WR) Watch Removed, (OP) Outlook Positive, (ON) Outlook Negative, (OS) Outlook Stable, (OD) Outlook Developing.

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Credit Ratings

New Jersey Resources Corporation (NYSE: NJR)

Subsidiary Credit Ratings Details		
	Moody's	**S&P**
New Jersey Natural Gas Co.		
Long-term Rating	(P)Aa3 (OS) Affirm *8/27/2010*	A (OS) Affirm *4/30/2009*
	Aa3 (OS) Affirm *12/22/2009*	A (ON) Downgrade *4/3/2008*
	Aa3 (ON) Affirm *12/17/2008*	A+ (ON) Affirm *6/19/2006*
	Aa3 (OS) Affirm *11/15/2003*	A+ Upgrade *9/3/2003*
	Aa3 Upgrade *9/4/2003*	A SNL Start
	A2 (WP) Affirm *6/25/2003*	-
Short-term/Commercial Paper	P-1 Affirm *11/15/2003*	A-1 Affirm *4/3/2008*
	P-1 Affirm *9/4/2003*	A-1 Affirm *6/19/2006*
	P-1 Affirm *6/25/2003*	A-1 Affirm *9/3/2003*
	P-1 Upgrade *11/8/1983*	A-1 Affirm *3/29/1979*
	P-2 SNL Start	A-1 SNL Start
Senior Secured Debt	(P)Aa3 (OS) Affirm *8/27/2010*	Remove *11/1/2008*
	Aa3 (OS) Affirm *12/22/2009*	A+ Downgrade *4/3/2008*
	Aa3 (ON) Affirm *12/17/2008*	AA- Affirm *6/19/2006*
	Aa3 (OS) Affirm *11/15/2003*	AA- Upgrade *9/3/2003*
	Aa3 Upgrade *9/4/2003*	A+ Upgrade *10/14/1997*
	A2 (WP) Affirm *6/25/2003*	A SNL Start

Ratings Watch Action Legend: (WP) Watch Positive, (WN) Watch Negative, (WU) Watch Uncertain, (WR) Watch Removed, (OP) Outlook Positive, (ON)

Credit Ratings

New Jersey Resources Corporation (NYSE: NJR)

Outlook Negative, (OS) Outlook Stable, (OD) Outlook Developing.

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Credit Ratings

Northwest Natural Gas Company (NYSE: NWN)

Credit Ratings

	Moody's	S&P	Fitch Ratings
Long-term Rating	(P)A3	A+	-
Outlook	Stable	Stable	-
Watch	-	-	-
As of Date	12/15/2008	1/25/2010	1/5/2007
	(P)A3 (OP) Affirm *7/13/2007*	AA- (ON) Affirm *12/19/2008*	A (OS) Affirm *12/6/2005*
	(P)A3 SNL Start *4/21/2004*	AA- (OS) Affirm *3/7/2006*	A (OS) Upgrade *6/7/2005*
	-	AA- (OS) Upgrade *2/28/2006*	A- Affirm *9/29/2004*
	-	A+ (OS) Upgrade *1/4/2005*	A- Affirm *9/26/2003*
	-	A (WR) Affirm *7/25/2002*	A- (WR) Affirm *9/6/2002*

Comparison with Peers : Moody's - SNL Default Peer Group

Company Name	Long-term Rating	Outlook	Watch	As of Date
Northwest Natural Gas Co.	(P)A3	Stable	-	12/15/2008
EQT Corp.	Baa2	Negative	-	11/2/2011
Energen Corp.	Baa3	Stable	-	9/24/2007
National Fuel Gas Co.	Baa1	Stable	-	4/28/2005
Laclede Group Inc.	(P)Baa2	Stable	-	11/15/2003

Credit Ratings Details

	Moody's	S&P	Fitch Ratings
Long-term Issuer	-	A+ (OS) Downgrade *1/25/2010*	Remove *1/5/2007*
	-	AA- (ON) Affirm *12/19/2008*	A (OS) Affirm *12/6/2005*
	-	AA- (OS) Affirm *3/7/2006*	A (OS) Upgrade *6/7/2005*
	-	AA- (OS) Upgrade *2/28/2006*	A- Affirm *9/29/2004*
	-	A+ (OS) Upgrade *1/4/2005*	A- Affirm *9/26/2003*
	-	A (WR) Affirm *7/25/2002*	A- (WR) Affirm *9/6/2002*
Senior Unsecured	(P)A3 (OS) Affirm *12/15/2008*	-	Remove *1/5/2007*

Northwest Natural Gas Company (NYSE: NWN)

	(P)A3 (OP) Affirm *7/13/2007*	-	A Upgrade *6/7/2005*
	(P)A3 Initiate *4/21/2004*	-	A- Affirm *9/29/2004*
	-	-	A- SNL Start
Short-term/Commercial Paper	P-1 Affirm *7/13/2007*	A-1 Downgrade *1/25/2010*	Remove *1/5/2007*
	P-1 (WR) Affirm *5/17/2002*	A-1+ Affirm *3/7/2006*	F1 Affirm *12/6/2005*
	P-1 (WN) Affirm *10/8/2001*	A-1+ Upgrade *2/28/2006*	F1 Affirm *6/7/2005*
	P-1 Affirm *5/11/1995*	A-1 Affirm *1/4/2005*	F1 Affirm *9/29/2004*
	P-1 SNL Start	A-1 (WR) Affirm *7/25/2002*	F1 Affirm *9/26/2003*
	-	A-1 (WN) Affirm *10/8/2001*	F1 (WR) Affirm *9/6/2002*
Preferred Stock	Remove *7/16/2007*	-	Remove *9/29/2004*
	Baa2 (WR) Affirm *5/17/2002*	-	A- Affirm *9/26/2003*
	Baa2 (WN) Affirm *10/8/2001*	-	A- (WR) Affirm *9/6/2002*
	Baa2 SNL Start	-	A- (WN) Affirm *10/8/2001*
	-	-	A- SNL Start
Senior Secured Debt	A1 Upgrade *8/3/2009*	A+ Downgrade *6/16/2010*	Remove *1/5/2007*
	A2 Affirm *7/13/2007*	AA- Upgrade *3/7/2006*	A+ Upgrade *6/7/2005*
	A2 (WR) Affirm *5/17/2002*	A+ Upgrade *1/4/2005*	A Affirm *9/29/2004*
	A2 (WN) SNL Start	A SNL Start *5/16/1991*	A Affirm *9/26/2003*
	-	-	A SNL Start

Ratings Watch Action Legend: (WP) Watch Positive, (WN) Watch Negative, (WU) Watch Uncertain, (WR) Watch Removed, (OP) Outlook Positive, (ON) Outlook Negative, (OS) Outlook Stable, (OD) Outlook Developing.

Credit Ratings

Northwest Natural Gas Company (NYSE: NWN)

Includes credit ratings on or after January 1, 2000. If a listed rating does not have a date, this means that while the rating was available from the ratings agency, the date was not available as of our data collection starting point. SNL does not publish revised Rating Outlooks independent of the credit rating itself. If there is a revised outlook where the credit rating stayed the same SNL lists this as a rating affirmation. Ratings history is comprehensive beginning with SNL's coverage of a company.

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Credit Ratings

Piedmont Natural Gas Company, Inc. (NYSE: PNY)

Credit Ratings

	Moody's	S&P
Long-term Rating	A3	A
Outlook	Stable	Stable
Watch	-	-
As of Date	4/28/2004	10/4/2007
	A3 Affirm *6/25/2003*	A (OS) Affirm *4/13/2004*
	A3 SNL Start	A (WR) Affirm *7/22/2003*
	-	A (WN) Affirm *10/17/2002*
	-	A Affirm *7/19/2002*
	-	A SNL Start *11/13/1992*

Comparison with Peers : Moody's - SNL Default Peer Group

Company Name	Long-term Rating	Outlook	Watch	As of Date
Piedmont Natural Gas Co. Inc.	A3	Stable	-	4/28/2004
EQT Corp.	Baa2	Negative	-	11/2/2011
Questar Corp.	A3	Stable	-	12/7/2010
Northwest Natural Gas Co.	(P)A3	Stable	-	12/15/2008
Energen Corp.	Baa3	Stable	-	9/24/2007
National Fuel Gas Co.	Baa1	Stable	-	4/28/2005
Laclede Group Inc.	(P)Baa2	Stable	-	11/15/2003

Credit Ratings Details

	Moody's	S&P
Long-term Issuer	-	A (OS) Affirm *10/4/2007*
	-	A (OS) Affirm *4/13/2004*
	-	A (WR) Affirm *7/22/2003*
	-	A (WN) Affirm *10/17/2002*
	-	A Affirm *7/19/2002*
	-	A SNL Start *11/13/1992*
	A3 (OS)	A

Piedmont Natural Gas Company, Inc. (NYSE: PNY)

Senior Unsecured	Affirm *4/28/2004*	Affirm *10/4/2007*
	A3 Affirm *6/25/2003*	A Affirm *4/13/2004*
	A3 SNL Start	A SNL Start
Short-term/Commercial Paper	P-2 Initiate *3/1/2012*	A-1 Initiate *3/1/2012*
	Remove *4/14/2004*	Remove *4/13/2004*
	P-2 SNL Start *7/25/2003*	A-1 SNL Start *7/22/2003*

Ratings Watch Action Legend: (WP) Watch Positive, (WN) Watch Negative, (WU) Watch Uncertain, (WR) Watch Removed, (OP) Outlook Positive, (ON) Outlook Negative, (OS) Outlook Stable, (OD) Outlook Developing.

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Credit Ratings

South Jersey Industries, Inc. (NYSE: SJI)

Credit Ratings

	S&P
Long-term Rating	BBB+
Outlook	Stable
Watch	-
As of Date	6/17/2011

Comparison with Peers : Moody's - SNL Default Peer Group

Company Name	Long-term Rating	Outlook	Watch	As of Date
EQT Corp.	Baa2	Negative	-	11/2/2011
Energen Corp.	Baa3	Stable	-	9/24/2007

Credit Ratings Details

	S&P
Long-term Issuer	BBB+ (OS) SNL Start *6/17/2011*

Subsidiary Credit Ratings Details

	Moody's	S&P
South Jersey Gas Co.		
Long-term Rating	A3 (OS) Upgrade *8/10/2012*	BBB+ (OS) Affirm *6/19/2006*
	Baa1 (OS) Affirm *3/4/2011*	BBB+ (ON) Affirm *3/29/2005*
	Baa1 Initiate *8/5/2009*	BBB+ Affirm *7/19/2002*
	WR Remove *2/1/2005*	BBB+ SNL Start *6/3/1993*
	Baa2 (OS) Initiate *1/4/1995*	-
Senior Unsecured	Remove *11/6/2008*	Remove *9/11/2006*
	Baa2 (OP) Initiate *10/12/2007*	BBB Affirm *6/19/2006*
	Remove *2/1/2005*	BBB Affirm *3/29/2005*
	Baa2 SNL Start *1/4/1995*	BBB SNL Start *12/21/1994*
Short-term/Commercial Paper	P-2 SNL Start *7/11/2011*	A-2 SNL Start *3/21/2011*
Trust Preferred	Remove *11/15/2003*	Remove *10/10/2008*
	Baa3	BBB-

South Jersey Industries, Inc. (NYSE: SJI)

	SNL Start	Affirm *6/19/2006*
	-	BBB- Affirm *3/29/2005*
	-	BBB- Downgrade *2/23/1999*
	-	BBB SNL Start
Senior Secured Debt	A1 Upgrade *8/10/2012*	A Affirm *6/19/2006*
	A2 Upgrade *8/3/2009*	A Affirm *3/29/2005*
	A3 (OP) Upgrade *2/4/2009*	A Upgrade *10/14/1997*
	Baa1 (WP) Affirm *11/6/2008*	BBB+ SNL Start
	Baa1 Affirm *10/12/2007*	-
	Baa1 SNL Start *6/29/1993*	-

Ratings News

Action items: S&P changes outlook on Cleco; Moody's upgrades South Jersey Gas ratings 8/29/2012 6:18 AM ET

SNL Energy presents a biweekly rundown of selected ratings actions on the U.S.-based energy companies. The changes — confined to upgrades, downgrades and changes in outlook — are listed by announcement date in reverse chronological order.

South Jersey Gas ratings upgraded by Moody's 8/14/2012 2:17 PM ET

Moody's has upgraded by one notch the senior secured and senior unsecured ratings of South Jersey Gas Co., to A1 and A3, respectively.

S&P assigns corporate credit rating to South Jersey Industries 6/19/2011 11:42 PM ET

S&P's rating on the company reflects strong predictable cash flows of its regulated natural gas utility, South Jersey Gas.

Moody's affirms South Jersey Gas ratings, lowers outlook to stable 3/7/2011 12:00 AM ET

About $250 million of debt securities are affected.

Ratings Watch Action Legend: (WP) Watch Positive, (WN) Watch Negative, (WU) Watch Uncertain, (WR) Watch Removed, (OP) Outlook Positive, (ON) Outlook Negative, (OS) Outlook Stable, (OD) Outlook Developing.

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South Jersey Industries, Inc. (NYSE: SJI)

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Credit Ratings

Southwest Gas Corporation (NYSE: SWX)

Credit Ratings

	Moody's	S&P	Fitch Ratings
Long-term Rating	Baa1	BBB+	BBB+
Outlook	Stable	Stable	Positive
Watch	-	-	-
As of Date	3/15/2012	4/27/2011	5/30/2012
	Baa2 (OS) Upgrade *5/27/2010*	BBB (OP) Affirm *4/22/2010*	BBB+ (OS) Upgrade *6/2/2011*
	Baa3 (OS) Downgrade *5/30/2006*	BBB (OS) Upgrade *4/24/2009*	BBB (OP) Affirm *6/1/2010*
	Baa2 (WN) Affirm *3/10/2006*	BBB- (OP) Affirm *3/13/2007*	BBB (OS) Affirm *4/29/2009*
	Baa2 Affirm *2/27/2004*	BBB- (OS) Affirm *8/11/2003*	BBB (OS) Affirm *2/1/2008*
	Baa2 SNL Start	BBB- Affirm *9/4/1990*	BBB (OS) Affirm *1/17/2007*

Comparison with Peers : Moody's - SNL Default Peer Group

Company Name	Long-term Rating	Outlook	Watch	As of Date
Southwest Gas Corp.	Baa1	Stable	-	3/15/2012
EQT Corp.	Baa2	Negative	-	11/2/2011
Questar Corp.	A3	Stable	-	12/7/2010
Northwest Natural Gas Co.	(P)A3	Stable	-	12/15/2008
Energen Corp.	Baa3	Stable	-	9/24/2007
National Fuel Gas Co.	Baa1	Stable	-	4/28/2005
Piedmont Natural Gas Co. Inc.	A3	Stable	-	4/28/2004
Laclede Group Inc.	(P)Baa2	Stable	-	11/15/2003

Credit Ratings Details

	Moody's	S&P	Fitch Ratings
Long-term Issuer	-	BBB+ (OS) Upgrade *4/27/2011*	BBB+ (OP) Affirm *5/30/2012*
	-	BBB (OP) Affirm *4/22/2010*	BBB+ (OS) Upgrade *6/2/2011*
	-	BBB (OS) Upgrade *4/24/2009*	BBB (OP) Affirm *6/1/2010*
	-	BBB- (OP) Affirm *3/13/2007*	BBB (OS) Affirm *4/29/2009*
	-	BBB- (OS) Affirm *8/11/2003*	BBB (OS) Affirm *2/1/2008*
	-	BBB- Affirm *9/4/1990*	BBB (OS) Affirm *1/17/2007*

Southwest Gas Corporation (NYSE: SWX)

Senior Unsecured	Baa1 (OS) Upgrade *3/15/2012*	BBB+ Upgrade *4/27/2011*	A- Upgrade *5/30/2012*
	Baa2 (OS) Upgrade *5/27/2010*	BBB Upgrade *4/24/2009*	BBB+ Upgrade *6/2/2011*
	Baa3 (OS) Downgrade *5/30/2006*	BBB- Affirm *3/13/2007*	BBB Affirm *2/1/2008*
	Baa2 (WN) Affirm *3/10/2006*	BBB- Affirm *8/11/2003*	BBB Affirm *1/17/2007*
	Baa2 Affirm *2/27/2004*	BBB- SNL Start	BBB Affirm *8/16/2005*
	Baa2 SNL Start	-	BBB Affirm *4/27/2004*
Short-term/Commercial Paper	-	-	F2 Affirm *5/30/2012*
	-	-	F2 Affirm *6/2/2011*
	-	-	F2 Affirm *6/1/2010*
	-	-	F2 Affirm *4/29/2009*
	-	-	F2 Affirm *2/1/2008*
	-	-	F2 Affirm *1/17/2007*
Trust Preferred	Remove *5/26/2010*	Remove *4/7/2010*	Remove *3/1/2010*
	Ba1 (OS) Downgrade *5/30/2006*	BB+ Upgrade *4/24/2009*	BB+ Downgrade *1/22/2010*
	Baa3 (WN) Affirm *3/10/2006*	BB Affirm *3/13/2007*	BBB- Affirm *2/1/2008*
	Baa3 Affirm *2/27/2004*	BB Downgrade *2/22/1999*	BBB- Affirm *1/17/2007*
	Baa3 SNL Start	BB+ SNL Start	BBB- Affirm *8/16/2005*
	-	-	BBB- Affirm *4/29/2004*

Ratings News

Fitch revises Southwest's ratings outlook to positive 5/30/2012 5:20 PM ET

Southwest Gas Corporation (NYSE: SWX)

Fitch Ratings on May 30 said it upgraded the senior unsecured ratings of Southwest Gas Corp., including industrial development revenue bonds, one-notch to A- from BBB+ and affirmed the long-term issuer default rating at BBB+.

Fitch upgrades ratings for Southwest Gas, revises outlook to stable 6/3/2011 12:00 AM ET

Fitch Ratings also affirmed the company's short-term issuer default rating and commercial paper at F2.

Ratings Watch Action Legend: (WP) Watch Positive, (WN) Watch Negative, (WU) Watch Uncertain, (WR) Watch Removed, (OP) Outlook Positive, (ON) Outlook Negative, (OS) Outlook Stable, (OD) Outlook Developing.

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Credit Ratings

MDU Resources Group, Inc. (NYSE: MDU)

Credit Ratings

	Moody's	S&P	Fitch Ratings
Long-term Rating	-	BBB+	A-
Outlook	-	Stable	Negative
Watch	-	-	-
As of Date	4/7/2011	7/10/2006	6/27/2012
	Baa1 (OS) Affirm *4/13/2010*	BBB+ (OS) Downgrade *2/28/2006*	A- (OS) Affirm *6/29/2011*
	Baa1 Downgrade *4/20/2009*	A- (ON) Affirm *12/17/2003*	A- (OS) Affirm *6/29/2010*
	A3 (WN) Affirm *2/5/2009*	A- (WR) Downgrade *1/8/2003*	A- (ON) Affirm *5/15/2009*
	A3 (OS) Affirm *7/11/2006*	A (WN) Affirm *5/20/2002*	A- (OS) Affirm *2/11/2008*
	A3 (OS) Affirm *11/15/2003*	A SNL Start	A- (OS) Affirm *4/18/2006*

Comparison with Peers : Moody's - SNL Default Peer Group

Company Name	Long-term Rating	Outlook	Watch	As of Date
MDU Resources Group Inc.	-	-	-	4/7/2011
Empire District Electric Co.	Baa2	Stable	-	5/14/2010
Otter Tail Corp.	Ba1	Stable	-	11/30/2009
ALLETE Inc.	Baa1	Stable	-	6/6/2008

Credit Ratings Details

	Moody's	S&P	Fitch Ratings
Long-term Issuer	Remove *4/7/2011*	BBB+ (OS) Affirm *7/10/2006*	A- (ON) Affirm *6/27/2012*
	Baa1 (OS) Affirm *4/13/2010*	BBB+ (OS) Downgrade *2/28/2006*	A- (OS) Affirm *6/29/2011*
	Baa1 Downgrade *4/20/2009*	A- (ON) Affirm *12/17/2003*	A- (OS) Affirm *6/29/2010*
	A3 (WN) Affirm *2/5/2009*	A- (WR) Downgrade *1/8/2003*	A- (ON) Affirm *5/15/2009*
	A3 (OS) Affirm *7/11/2006*	A (WN) Affirm *5/20/2002*	A- (OS) Affirm *2/11/2008*
	A3 (OS) Affirm *11/15/2003*	A SNL Start	A- (OS) Affirm *4/18/2006*
Senior Unsecured	Remove *4/7/2011*	BBB+ SNL Start *7/19/2011*	A Affirm *6/27/2012*
	Baa1 SNL Start	-	A Affirm

	3/9/2010		*6/29/2011*
	-	-	A Affirm *2/11/2008*
	-	-	A SNL Start
Short-term/Commercial Paper	Remove *4/7/2011*	A-2 Affirm *7/10/2006*	F2 Affirm *6/27/2012*
	P-2 Downgrade *4/20/2009*	A-2 Affirm *2/28/2006*	F2 Affirm *6/29/2011*
	P-1 (WN) Affirm *2/5/2009*	A-2 Affirm *12/17/2003*	F2 Affirm *6/29/2010*
	P-1 Affirm *11/15/2003*	A-2 Downgrade *1/8/2003*	F2 Downgrade *5/15/2009*
	P-1 Upgrade *1/29/1997*	A-1 (WN) Affirm *5/20/2002*	F1 Affirm *2/11/2008*
	P-2 SNL Start	A-1 SNL Start	F1 Affirm *4/18/2006*
Preferred Stock	Remove *4/7/2011*	Remove *6/29/2011*	BBB+ Affirm *6/27/2012*
	Baa3 Downgrade *4/20/2009*	BBB- Affirm *7/10/2006*	BBB+ Affirm *6/29/2011*
	Baa2 (WN) Affirm *2/5/2009*	BBB- Downgrade *2/28/2006*	BBB+ Downgrade *1/22/2010*
	Baa2 SNL Start	BBB Affirm *12/17/2003*	A- Affirm *2/11/2008*
	-	BBB (WR) Downgrade *1/8/2003*	A- Affirm *4/18/2006*
	-	BBB+ (WN) SNL Start	A- Affirm *10/12/2004*
Senior Secured Debt	Remove *4/9/2010*	BBB+ Initiate *7/19/2011*	Remove *6/29/2010*
	A3 Downgrade *4/20/2009*	Remove *6/29/2011*	A+ Affirm *2/11/2008*
	A2 (WN) Affirm *2/5/2009*	A- Affirm *7/10/2006*	A+ Affirm *4/18/2006*
	A2 Upgrade *1/29/1997*	A- Affirm *2/28/2006*	A+ Affirm *10/12/2004*
	A3 SNL Start	A- Affirm *12/17/2003*	A+ Affirm *8/4/2003*
	-	A- (WR)	A+

		Downgrade *1/8/2003*	SNL Start

Subsidiary Credit Ratings Details

	Moody's	S&P	Fitch Ratings
Cascade Natural Gas Corp.			
Long-term Rating	Remove *4/7/2011*	BBB+ (OS) Initiate *4/5/2011*	A- (ON) Affirm *6/27/2012*
	Baa1 (OS) Affirm *4/20/2009*	Remove *2/7/2008*	A- (OS) Affirm *6/29/2011*
	Baa1 Affirm *2/5/2009*	BBB+ (OS) Affirm *7/6/2007*	A- (OS) Affirm *6/29/2010*
	Baa1 (OS) Affirm *7/26/2007*	BBB+ (OS) Affirm *7/10/2006*	A- (ON) Affirm *5/15/2009*
	Baa1 (OS) Affirm *11/15/2003*	BBB+ (OS) Affirm *8/24/2005*	A- (OS) Affirm *2/11/2008*
	Baa1 Affirm *9/5/2003*	BBB+ Affirm *6/30/2004*	A- (OS) SNL Start *7/13/2007*
Senior Unsecured	Remove *4/7/2011*	BBB+ Initiate *8/19/2011*	A Affirm *6/27/2012*
	Baa1 (OS) Affirm *4/20/2009*	Remove *2/7/2008*	A Affirm *6/29/2011*
	Baa1 Affirm *2/5/2009*	BBB+ Affirm *7/6/2007*	A Affirm *2/11/2008*
	Baa1 (OS) Affirm *7/26/2007*	BBB+ Affirm *7/10/2006*	A SNL Start *7/13/2007*
	Baa1 (OS) Affirm *11/15/2003*	BBB+ Affirm *8/24/2005*	-
	Baa1 Affirm *9/5/2003*	BBB+ Affirm *6/30/2004*	-
Short-term/Commercial Paper	-	-	F2 Affirm *6/27/2012*
	-	-	F2 Affirm *6/29/2011*
	-	-	F2 Affirm *6/29/2010*
	-	-	F2 Downgrade *5/15/2009*
	-	-	F1 Affirm *2/11/2008*
	-	-	F1

			SNL Start *7/13/2007*
Centennial Energy Holdings Inc.			
Long-term Rating	-	BBB+ (OS) SNL Start *2/28/2006*	BBB+ (ON) Affirm *6/27/2012*
	-	-	BBB+ (OS) Affirm *6/29/2011*
	-	-	BBB+ (OS) Downgrade *6/29/2010*
	-	-	A- (ON) Affirm *5/15/2009*
	-	-	A- (OS) Affirm *2/11/2008*
	-	-	A- (OS) SNL Start *4/18/2006*
Short-term/Commercial Paper	Remove *4/7/2011*	A-2 SNL Start *1/8/2003*	F2 Affirm *6/27/2012*
	NP (WR) Downgrade *4/20/2009*	-	F2 Affirm *6/29/2011*
	P-2 (WN) Affirm *2/5/2009*	-	F2 Affirm *6/29/2010*
	P-2 Affirm *11/15/2003*	-	F2 Downgrade *5/15/2009*
	P-2 SNL Start *11/11/1998*	-	F1 Affirm *2/11/2008*
	-	-	F1 SNL Start *4/18/2006*
Montana-Dakota Utilities Co			
Long-term Rating	-	BBB+ (OS) SNL Start *2/28/2006*	-

Ratings News

Fitch affirms ratings of MDU Resources, subsidiaries 7/1/2011 8:53 AM ET

The rating outlook for all entities is stable. About $1.4 billion of debt is affected by the ratings actions, Fitch said.

Moody's withdraws debt ratings of MDU Resources, subsidiaries 4/8/2011 1:36 PM ET

The rating agency also changed outlooks for MDU Resources, Cascade Natural Gas and Centennial Energy to rating withdrawn from stable.

Ratings Watch Action Legend: (WP) Watch Positive, (WN) Watch Negative, (WU) Watch Uncertain, (WR) Watch Removed, (OP) Outlook Positive, (ON) Outlook Negative, (OS) Outlook Stable, (OD) Outlook Developing.

Includes credit ratings on or after January 1, 2000. If a listed rating does not have a date, this means that while the rating was available from the ratings agency, the date was not available as of our data collection starting point. SNL does not publish revised Rating Outlooks independent of the credit rating itself. If there is a revised outlook where the credit rating stayed the same SNL lists this as a rating affirmation. Ratings history is comprehensive beginning

with SNL's coverage of a company.

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Response No. MCC-092
Attachment E

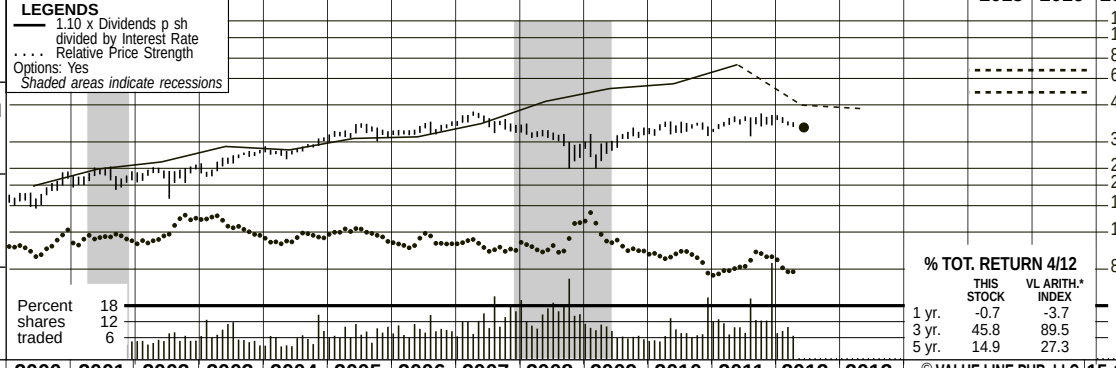
AGL RESOURCES NYSE-GAS

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
37.54	13.4	(Trailing: 21.8 Median: 13.0)	0.93	4.9%	VALUE LINE

TIMELINESS 3 Raised 3/11/11
SAFETY 1 Raised 9/9/11
TECHNICAL 3 Raised 5/18/12
BETA .75 (1.00 = Market)

High:	24.5	25.0	29.3	33.7	39.3	40.1	44.7	39.1	37.5	40.1	43.7	42.9
Low:	19.0	17.3	21.9	26.5	32.0	34.4	35.2	24.0	24.0	34.2	34.1	36.6

Target Price Range
2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+85%)	17%
Low	55	(+45%)	10%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	1	1	0	1	1	0
to Sell	0	0	0	1	2	0	0	1	0

Institutional Decisions

	2Q2011	3Q2011	4Q2011
to Buy	109	99	258
to Sell	104	118	63
Hld's(000)	50316	50506	71384

% TOT. RETURN 4/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-0.7	-3.7
3 yr.	45.8	89.5
5 yr.	14.9	27.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
21.91	22.75	23.36	18.71	11.25	19.04	15.32	15.25	23.89	34.98	33.73	32.64	36.41	29.88	30.42	20.00	*40.25*	*42.00*	Revenues per sh A	*47.50*
2.49	2.42	2.65	2.29	2.86	3.31	3.39	3.47	3.29	4.20	4.50	4.65	4.68	4.90	5.05	3.05	*6.55*	*6.85*	"Cash Flow" per sh	*7.75*
1.37	1.37	1.41	.91	1.29	1.50	1.82	2.08	2.28	2.48	2.72	2.72	2.71	2.88	3.00	2.12	*2.80*	*3.10*	Earnings per sh A B	*4.10*
1.06	1.08	1.08	1.08	1.08	1.08	1.08	1.11	1.15	1.30	1.48	1.64	1.68	1.72	1.76	2.26	*1.74*	*1.84*	Div'ds Decl'd per sh C■	*2.00*
2.37	2.59	2.05	2.51	2.92	2.83	3.30	2.46	3.44	3.44	3.26	3.39	4.84	6.14	6.54	3.42	*5.75*	*5.90*	Cap'l Spending per sh	*6.30*
10.56	10.99	11.42	11.59	11.50	12.19	12.52	14.66	18.06	19.29	20.71	21.74	21.48	22.95	23.24	28.54	*30.05*	*31.85*	Book Value per sh D	*36.35*
55.70	56.60	57.30	57.10	54.00	55.10	56.70	64.50	76.70	77.70	77.70	76.40	76.90	77.54	78.00	117.00	*118.00*	*119.00*	Common Shs Outst'g E	*121.00*
13.8	14.7	13.9	21.4	13.6	14.6	12.5	12.5	13.1	14.3	13.5	14.7	12.3	11.2	12.5	12.6	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.86	.85	.72	1.22	.88	.75	.68	.71	.69	.76	.73	.78	.74	.75	.80	.82	*Value Line*		Relative P/E Ratio	*1.00*
5.6%	5.4%	5.5%	5.5%	6.2%	4.9%	4.7%	4.3%	3.9%	3.7%	4.0%	4.1%	5.0%	5.4%	4.7%	4.8%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 3/31/12
Total Debt $4288.0 mill. **Due in 5 Yrs** $950.0 mill.
LT Debt $3558.0 mill. **LT Interest** $190.0 mill.
(Total interest coverage: 6.5x)

Leases, Uncapitalized Annual rentals $95.0 mill.
Pension Assets-12/11 $754.0 mill. **Oblig.** $968.0 mill.

Pfd Stock None

Common Stock 117,310,372 shs. **as of 4/26/12**

MARKET CAP: $4.4 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
868.9	983.7	1832.0	2718.0	2621.0	2494.0	2800.0	2317.0	2373.0	2338.0	*4750*	*5000*	Revenues ($mill) A	*5750*
103.0	132.4	153.0	193.0	212.0	211.0	207.6	222.0	234.0	172.0	*330*	*370*	Net Profit ($mill)	*495*
36.0%	35.9%	37.0%	37.7%	37.8%	37.6%	40.5%	35.2%	35.9%	40.2%	*40.0%*	*40.0%*	Income Tax Rate	*40.0%*
11.9%	13.5%	8.4%	7.1%	8.1%	8.5%	7.4%	9.6%	9.9%	7.4%	*7.0%*	*7.4%*	Net Profit Margin	*8.6%*
58.3%	50.3%	54.0%	51.9%	50.2%	50.2%	50.3%	52.6%	48.0%	52.0%	*50.0%*	*48.0%*	Long-Term Debt Ratio	*43.0%*
41.7%	49.7%	46.0%	48.1%	49.8%	49.8%	49.7%	47.4%	52.0%	48.0%	*50.0%*	*52.0%*	Common Equity Ratio	*57.0%*
1704.3	1901.4	3008.0	3114.0	3231.0	3335.0	3327.0	3754.0	3486.0	8238.0	*7015*	*7075*	Total Capital ($mill)	*7260*
2194.2	2352.4	3178.0	3271.0	3436.0	3566.0	3816.0	4146.0	4405.0	7900.0	*8035*	*8175*	Net Plant ($mill)	*8470*
8.1%	8.9%	6.3%	7.9%	8.0%	7.7%	7.4%	6.9%	7.6%	3.0%	*5.5%*	*6.0%*	Return on Total Cap'l	*7.5%*
14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	12.5%	12.9%	5.2%	*9.5%*	*10.0%*	Return on Shr. Equity	*12.0%*
14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	12.5%	12.9%	5.2%	*9.5%*	*10.0%*	Return on Com Equity	*12.0%*
7.0%	6.6%	5.6%	6.2%	6.3%	5.3%	5.1%	5.3%	5.6%	.7%	*4.5%*	*4.0%*	Retained to Com Eq	*6.0%*
52%	53%	49%	52%	52%	58%	60%	57%	57%	86%	*49%*	*62%*	All Div'ds to Net Prof	*49%*

CURRENT POSITION ($MILL.)	2010	2011	3/31/12
Cash Assets	24.0	69.0	71.0
Other	2138.0	2677.0	1951.0
Current Assets	2162.0	2746.0	2022.0
Accts Payable	184.0	294.0	205.0
Debt Due	1032.0	1338.0	730.0
Other	1212.0	1452.0	1413.0
Current Liab.	2428.0	3984.0	2348.0
Fix. Chg. Cov.	501%	325%	465%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	6.0%	5.5%	*-2.5%*
"Cash Flow"	6.5%	6.0%	*2.5%*
Earnings	9.0%	4.5%	*5.5%*
Dividends	5.0%	7.5%	*2.0%*
Book Value	7.0%	5.5%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	995.0	377.0	307.0	638.0	2317.0
2010	1003	359.0	346.0	665.0	2373.0
2011	878.0	375.0	295.0	790.0	2338.0
2012	1404	*700*	*1000*	*1646*	*4750*
2013	*1600*	*800*	*1000*	*1600*	*5000*

Cal-endar	EARNINGS PER SHARE AB Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1.55	.26	.16	.91	2.88
2010	1.73	.17	.29	.81	3.00
2011	1.59	.23	d.04	.37	2.12
2012	1.16	*.35*	*.45*	*.84*	*2.80*
2013	*1.50*	*.35*	*.50*	*.75*	*3.10*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.42	.42	.42	.42	1.68
2009	.43	.43	.43	.43	1.72
2010	.44	.44	.44	.44	1.76
2011	.45	.45	.45	.55	2.26
2012	.36	.46			

BUSINESS: AGL Resources Inc. is a public utility holding company. Its distribution subsidiaries include Atlanta Gas Light, Chattanooga Gas, Elizabethtown Gas, and Virginia Natural Gas. The utilities have more than 2.3 million customers in Georgia, Virginia, Tennessee, New Jersey, Florida, and Maryland. Engaged in non-regulated natural gas marketing and other allied services. Deregulated subsidiaries: Georgia Natural Gas markets natural gas at retail. Sold Utilipro, 3/01. Acquired Compass Energy Services, 10/07. BlackRock Inc. owns 6.8% of common stock; off./dir., less than 1.0% (3/12 Proxy). Pres. & CEO: John W. Somerhalder II. Inc.: GA. Addr.: Ten Peachtree Place N.E., Atlanta, GA 30309. Telephone: 404-584-4000. Internet: www.aglresources.com.

The newly merged AGL Resources had a lackluster first quarter. Per-share earnings fell to $1.16, a 27% drop from the March, 2011 period. Warmer-than-expected weather was the main reason for the decline. Thus, we have lowered our full-year estimate by $0.45, to $2.80.

Several obstacles could hinder growth for the next few years. Concerns include subpar customer growth, owing to the slow recovery in the housing market, and a lack of new rate case filings. We also remain concerned about low natural gas storage demand (storage inventories are reaching record highs due to a supply glut), which could impact contracted rates and terms at the company's midstream segment. In turn, both factors could provide headwinds for both the top and bottom lines.

New contracts might ease some of the upcoming pressure. Despite the lower storage demand (above), Sequent Energy Management's brand strength has netted it several new storage contracts, along with various renewed contracts. Management hopes to lock in additional contracts as the year goes on, and these should work to partly offset some of the stress on revenues and earnings, though their full impact is uncertain at this point.

The long term offers some promise, although there are also some uncertanties. As a result of favorable rate rulings over the past few years, AGL Resources is expecting a considerable boost to revenues going forward. Furthermore, its merger with Nicor makes it the largest natural gas distributor in the country, with a particularly strong position in the Midwest. Thus, a rise in volumes via core growth could result in a strong profit showing. However, we remain concerned that increasing competition at the retail level in Georgia could hold back the bottom line, and thus hurt the 2015-2017 period performace. Sideline businesses could be hurt by low gas prices too.

This neutrally ranked equity has below-average appreciation potential, but income investors will find it most appealing. With its normalized quaterly payouts now at $0.46 a share, the stock offers an above-industry average dividend yield, and strong possibility of future payout hikes.

Sahana Zutshi *June 8, 2012*

(A) Fiscal year ends December 31st. Ended September 30th prior to 2002.
(B) Diluted earnings per share. Excl. nonrecurring gains (losses):'99, $0.39; '00, $0.13; '01, $0.13; '03, ($0.07); '08, $0.13. Next earnings report due late July.
(C) Dividends historically paid early March, June, Sept., and Dec. ■ Div'd reinvest. plan available. (D) Includes intangibles. In 2011: $1918 million, $16.40/share.
(E) In millions.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	90

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ATMOS ENERGY CORP. NYSE-ATO

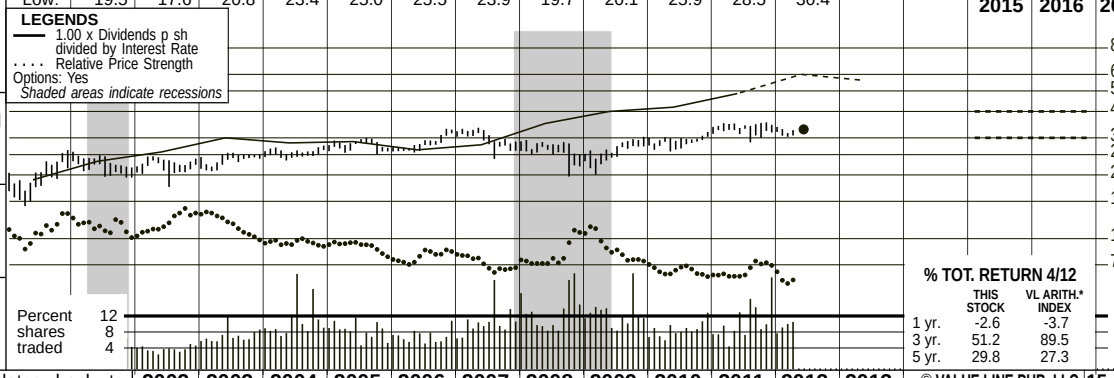
RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
32.90	15.7	(Trailing: 17.0 Median: 14.0)	1.09	4.3%	VALUE LINE

TIMELINESS 3 Raised 3/30/12
SAFETY 2 Raised 12/16/05
TECHNICAL 4 Lowered 5/25/12
BETA .70 (1.00 = Market)

High:	25.8	24.5	25.5	27.6	30.0	33.1	33.5	29.3	30.3	32.0	35.6	33.9
Low:	19.5	17.6	20.8	23.4	25.0	25.5	23.9	19.7	20.1	25.9	28.5	30.4

Target Price Range
2015 | 2016 | 2017

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+20%)	9%
Low	30	(-10%)	2%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	1	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	2	0	0	0	1

Institutional Decisions

	2Q2011	3Q2011	4Q2011
to Buy	112	110	132
to Sell	105	116	103
Hld's(000)	50093	50338	48646

Percent shares traded 12 8 4

% TOT. RETURN 4/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-2.6	-3.7
3 yr.	51.2	89.5
5 yr.	29.8	27.3

Atmos Energy's history dates back to 1906 in the Texas Panhandle. Over the years, through various mergers, it became part of Pioneer Corporation, and, in 1981, Pioneer named its gas distribution division Energas. In 1983, Pioneer organized Energas as a separate subsidiary and distributed the outstanding shares of Energas to Pioneer shareholders. Energas changed its name to Atmos in 1988. Atmos acquired Trans Louisiana Gas in 1986, Western Kentucky Gas Utility in 1987, Greeley Gas in 1993, United Cities Gas in 1997, and others.

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
22.82	54.39	46.50	61.75	75.27	66.03	79.52	53.69	53.12	48.15	*44.55*	*49.00*	Revenues per sh A	*63.10*
3.39	3.23	2.91	3.90	4.26	4.14	4.19	4.29	4.64	4.72	*4.65*	*5.05*	"Cash Flow" per sh	*5.65*
1.45	1.71	1.58	1.72	2.00	1.94	2.00	1.97	2.16	2.26	*2.00*	*2.30*	Earnings per sh A B	*2.70*
1.18	1.20	1.22	1.24	1.26	1.28	1.30	1.32	1.34	1.36	*1.38*	*1.40*	Div'ds Decl'd per sh C■	*1.48*
3.17	3.10	3.03	4.14	5.20	4.39	5.20	5.51	6.02	6.90	*7.75*	*7.95*	Cap'l Spending per sh	*8.80*
13.75	16.66	18.05	19.90	20.16	22.01	22.60	23.52	24.16	24.98	*28.75*	*30.00*	Book Value per sh	*34.65*
41.68	51.48	62.80	80.54	81.74	89.33	90.81	92.55	90.16	90.30	*90.00*	*91.00*	Common Shs Outst'g D	*103.00*
15.2	13.4	15.9	16.1	13.5	15.9	13.6	12.5	13.2	14.4	*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
.83	.76	.84	.86	.73	.84	.82	.83	.84	.90	*Value Line*		Relative P/E Ratio	*.85*
5.4%	5.2%	4.9%	4.5%	4.7%	4.2%	4.8%	5.3%	4.7%	4.2%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*
950.8	2799.9	2920.0	4973.3	6152.4	5898.4	7221.3	4969.1	4789.7	4347.6	*4010*	*4460*	Revenues ($mill) A	*6500*
59.7	79.5	86.2	135.8	162.3	170.5	180.3	179.7	201.2	199.3	*180*	*210*	Net Profit ($mill)	*280*
37.1%	37.1%	37.4%	37.7%	37.6%	35.8%	38.4%	34.4%	38.5%	36.4%	*38.5%*	*38.5%*	Income Tax Rate	*38.5%*
6.3%	2.8%	3.0%	2.7%	2.6%	2.9%	2.5%	3.6%	4.2%	4.6%	*4.5%*	*4.7%*	Net Profit Margin	*4.3%*
53.9%	50.2%	43.2%	57.7%	57.0%	52.0%	50.8%	49.9%	45.4%	49.4%	*46.5%*	*48.5%*	Long-Term Debt Ratio	*49.0%*
46.1%	49.8%	56.8%	42.3%	43.0%	48.0%	49.2%	50.1%	54.6%	50.6%	*53.5%*	*51.5%*	Common Equity Ratio	*51.0%*
1243.7	1721.4	1994.8	3785.5	3828.5	4092.1	4172.3	4346.2	3987.9	4461.5	*4840*	*5300*	Total Capital ($mill)	*7000*
1300.3	1516.0	1722.5	3374.4	3629.2	3836.8	4136.9	4439.1	4793.1	5147.9	*5500*	*5800*	Net Plant ($mill)	*6700*
6.8%	6.2%	5.8%	5.3%	6.1%	5.9%	5.9%	5.9%	6.9%	6.1%	*5.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	8.3%	9.2%	8.8%	*7.0%*	*7.5%*	Return on Shr. Equity	*8.0%*
10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	8.3%	9.2%	8.8%	*7.0%*	*7.5%*	Return on Com Equity	*8.0%*
1.9%	2.8%	1.7%	2.3%	3.6%	3.0%	3.1%	2.7%	3.5%	3.3%	*2.0%*	*3.0%*	Retained to Com Eq	*3.5%*
82%	70%	77%	73%	63%	65%	65%	68%	62%	62%	*69%*	*61%*	All Div'ds to Net Prof	*54%*

CAPITAL STRUCTURE as of 3/31/12
Total Debt $2380.3 mill. **Due in 5 Yrs** $660.0 mill.
LT Debt $1956.2 mill. **LT Interest** $110.0 mill.
(LT interest earned: 3.1x; total interest coverage: 3.1x)
Leases, Uncapitalized Annual rentals $17.7 mill.
Pfd Stock None
Pension Assets-9/11 $280.2 mill. **Oblig.** $429.4 mill.
Common Stock 90,030,471 shs. **as of 4/27/12**
MARKET CAP: $3.0 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2010	2011	3/31/12
Cash Assets	132.0	131.4	47.0
Other	743.2	879.6	846.8
Current Assets	875.2	1011.0	893.8
Accts Payable	266.2	291.2	309.9
Debt Due	486.2	208.8	424.1
Other	413.7	367.6	374.1
Current Liab.	1166.1	867.6	1108.1
Fix. Chg. Cov.	440%	432%	430%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	6.5%	-3.5%	*3.5%*
"Cash Flow"	4.5%	4.5%	*3.5%*
Earnings	7.0%	4.0%	*4.0%*
Dividends	1.5%	1.5%	*1.5%*
Book Value	6.5%	4.5%	*6.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	1716.3	1821.4	780.8	650.6	4969.1
2010	1292.9	1940.3	770.2	786.3	4789.7
2011	1133.3	1581.5	843.6	789.2	4347.6
2012	1101.2	1243.4	*870*	*795.4*	*4010*
2013	*1205*	*1600*	*850*	*805*	*4460*

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	.83	1.29	.02	d.17	1.97
2010	1.00	1.17	d.03	.02	2.16
2011	.81	1.40	.04	.01	2.26
2012	.72	1.16	*.09*	*.03*	*2.00*
2013	*.82*	*1.38*	*.07*	*.03*	*2.30*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.325	.325	.325	.33	1.31
2009	.33	.33	.33	.335	1.33
2010	.335	.335	.335	.34	1.35
2011	.34	.34	.34	.345	1.37
2012	.345	.345			

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over three million customers via six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Combined 2011 gas volumes: 281.5 MMcf. Breakdown: 57%, residential; 32%, commercial; 7%, industrial; and 4% other. 2011 depreciation rate 3.3%. Has around 4,750 employees. Officers and directors own 1.5% of common stock (12/11 Proxy). President and Chief Executive Officer: Kim R. Cocklin. Inc.: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy Corporation's core natural gas distribution unit registered a drop in profits during the first half of fiscal 2012. (Years end on September 30th.) That was attributed partly to a 10% decline in throughput, as warmer weather constrained consumption. Furthermore, revenue-related taxes were lower, due to decreased revenues on which the tax is calculated. But the segment benefited from rate hikes, especially in the Texas, Louisiana, Mississippi, and Kentucky service areas.

The other businesses had mixed performances. The nonregulated division suffered from unfavorable pricing conditions in the natural gas market, arising from a combination of abundant supply and diminished demand. Meanwhile, results for the regulated transmission and storage segment were aided by rate design adjustments approved in the Atmos Pipeline—Texas case that became effective in May, 2011.

It appears that consolidated share net will fall more than 10%, to $2.00, this fiscal year. Still, assuming that units presently struggling perk up, the bottom line stands to bounce back to $2.30 a share in fiscal 2013.

There are plans to sell the natural gas distribution operations in Missouri, Iowa, and Illinois (serving around 84,000 customers) to an affiliate of Algonquin Power & Utilities Corp. The estimated $124 million in proceeds would be used to support growth initiatives in such key states as Texas and Louisiana. Pending regulatory approvals, the transaction is expected to close sometime during fiscal 2012. Please note that our presentation accounts for those businesses as discontinued.

The stock's dividend yield ranks favorably compared to that of other gas utility equities covered by *Value Line*. Our 3- to 5-year projections indicate that additional, although moderate, increases in the distribution are likely to occur. The payout ratio ought to remain within a manageable range (i.e., 55% to 60%). What's more, these shares hold a 2 (Above Average) Safety rating and an excellent score for Price Stability. But the Timeliness rank is only 3 (Average).

Frederick L. Harris, III *June 8, 2012*

(A) Fiscal year ends Sept. 30th. **(B)** Diluted shrs. Excl. nonrec. items: '03, d17¢; '06, d18¢; '07, d2¢; '09, 12¢; '10, 5¢; '11, (1¢). Excludes discontinued operations: '11, 10¢; '12, 6¢. Next egs. rpt. due early Aug. **(C)** Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. **(D)** In millions. **(E)** Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	90

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LACLEDE GROUP NYSE-LG

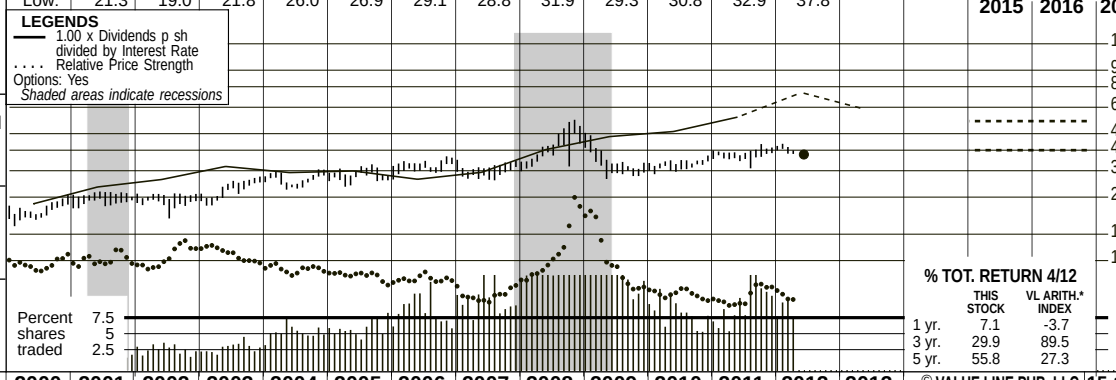
RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
38.19	15.1	(Trailing: 12.7 Median: 14.0)	1.05	4.3%	VALUE LINE

TIMELINESS 3 Lowered 9/23/11
SAFETY 2 Raised 6/20/03
TECHNICAL 3 Raised 5/11/12
BETA .55 (1.00 = Market)

High:	25.5	25.0	30.0	32.5	34.3	37.5	36.0	55.8	48.3	37.8	42.8	43.0
Low:	21.3	19.0	21.8	26.0	26.9	29.1	28.8	31.9	29.3	30.8	32.9	37.8

Target Price Range
2015 | 2016 | 2017

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+45%)	13%
Low	40	(+5%)	6%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	2	0	0	1
to Sell	0	0	0	0	0	2	0	0	1

Institutional Decisions

	2Q2011	3Q2011	4Q2011
to Buy	62	72	64
to Sell	57	55	58
Hld's(000)	10630	10983	10812

% TOT. RETURN 4/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	7.1	-3.7
3 yr.	29.9	89.5
5 yr.	55.8	27.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
31.03	34.33	31.04	26.04	29.99	53.08	39.84	54.95	59.59	75.43	93.51	93.40	100.44	85.49	77.83	71.48	*65.20*	*65.95*	Revenues per sh	*76.00*
3.29	3.32	3.02	2.56	2.68	3.00	2.56	3.15	2.79	2.98	3.81	3.87	4.22	4.56	4.11	4.62	*4.30*	*4.60*	"Cash Flow" per sh	*5.40*
1.87	1.84	1.58	1.47	1.37	1.61	1.18	1.82	1.82	1.90	2.37	2.31	2.64	2.92	2.43	2.86	*2.55*	*2.70*	Earnings per sh A B	*3.00*
1.26	1.30	1.32	1.34	1.34	1.34	1.34	1.34	1.35	1.37	1.40	1.45	1.49	1.53	1.57	1.61	*1.65*	*1.69*	Div'ds Decl'd per sh C■	*1.81*
2.35	2.44	2.68	2.58	2.77	2.51	2.80	2.67	2.45	2.84	2.97	2.72	2.57	2.36	2.56	3.02	*3.70*	*3.85*	Cap'l Spending per sh	*4.20*
13.72	14.26	14.57	14.96	14.99	15.26	15.07	15.65	16.96	17.31	18.85	19.79	22.12	23.32	24.02	25.56	*25.85*	*26.30*	Book Value per sh D	*27.00*
17.56	17.56	17.63	18.88	18.88	18.88	18.96	19.11	20.98	21.17	21.36	21.65	21.99	22.17	22.29	22.43	*23.00*	*23.50*	Common Shs Outst'g E	*25.00*
11.9	12.5	15.5	15.8	14.9	14.5	20.0	13.6	15.7	16.2	13.6	14.2	14.3	13.4	13.7	13.0	*Bold figures are*		Avg Ann'l P/E Ratio	*15.5*
.75	.72	.81	.90	.97	.74	1.09	.78	.83	.86	.73	.75	.86	.89	.87	.81	*Value Line*		Relative P/E Ratio	*1.05*
5.6%	5.6%	5.4%	5.8%	6.6%	5.7%	5.7%	5.4%	4.7%	4.4%	4.3%	4.4%	3.9%	3.9%	4.7%	4.3%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 3/31/12
Total Debt $364.4 mill. **Due in 5 Yrs** $70.0 mill.
LT Debt $339.4 mill. **LT Interest** $20.0 mill.
(Total interest coverage: 4.7x)

Leases, Uncapitalized Annual rentals $.9 mill.
Pension Assets-9/11 $248.0 mill. **Oblig.** $384.2 mill.
Pfd Stock None
Common Stock 22,486,766 shs. **as of 4/26/12**

MARKET CAP: $850 million (Small Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
755.2	1050.3	1250.3	1597.0	1997.6	2021.6	2209.0	1895.2	1735.0	1603.3	*1500*	*1550*	Revenues ($mill) A	*1900*
22.4	34.6	36.1	40.1	50.5	49.8	57.6	64.3	54.0	63.8	*58.0*	*63.5*	Net Profit ($mill)	*75.0*
35.4%	35.0%	34.8%	34.1%	32.5%	33.4%	31.3%	33.6%	33.4%	31.4%	*33.0%*	*33.0%*	Income Tax Rate	*33.0%*
3.0%	3.3%	2.9%	2.5%	2.5%	2.5%	2.6%	3.4%	3.1%	4.0%	*3.9%*	*4.1%*	Net Profit Margin	*4.0%*
47.5%	50.4%	51.6%	48.1%	49.5%	45.3%	44.4%	42.9%	40.5%	38.9%	*36.0%*	*34.0%*	Long-Term Debt Ratio	*31.0%*
52.3%	49.4%	48.3%	51.8%	50.4%	54.6%	55.5%	57.1%	59.5%	61.1%	*64.0%*	*66.0%*	Common Equity Ratio	*69.0%*
546.6	605.0	737.4	707.9	798.9	784.5	876.1	906.3	899.9	937.7	*925*	*940*	Total Capital ($mill)	*985*
594.4	621.2	646.9	679.5	763.8	793.8	823.2	855.9	884.1	928.7	*945*	*965*	Net Plant ($mill)	*1005*
6.0%	7.4%	6.6%	7.6%	8.4%	8.5%	8.1%	8.7%	7.4%	8.1%	*7.5%*	*7.5%*	Return on Total Cap'l	*8.0%*
7.8%	11.5%	10.1%	10.9%	12.5%	11.6%	11.8%	12.4%	10.1%	11.1%	*10.0%*	*10.0%*	Return on Shr. Equity	*11.0%*
7.8%	11.6%	10.1%	10.9%	12.5%	11.6%	11.8%	12.4%	10.1%	11.1%	*10.0%*	*10.0%*	Return on Com Equity	*11.0%*
NMF	3.1%	2.7%	3.1%	5.1%	4.3%	5.2%	5.9%	3.6%	4.9%	*3.5%*	*4.0%*	Retained to Com Eq	*4.5%*
113%	74%	73%	72%	59%	63%	56%	53%	64%	56%	*65%*	*63%*	All Div'ds to Net Prof	*60%*

CURRENT POSITION ($MILL.)	2010	2011	3/31/12
Cash Assets	86.9	43.3	9.3
Other	327.3	325.8	268.5
Current Assets	414.2	369.1	277.8
Accts Payable	95.6	96.6	73.0
Debt Due	154.6	46.0	25.0
Other	83.7	89.3	89.8
Current Liab.	333.9	231.9	187.8
Fix. Chg. Cov.	391%	463%	472%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	8.0%	.5%	*Nil*
"Cash Flow"	5.0%	7.0%	*3.0%*
Earnings	6.5%	6.0%	*2.0%*
Dividends	1.5%	2.5%	*2.5%*
Book Value	5.0%	6.5%	*4.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.)A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	674.3	659.1	309.9	251.9	1895.2
2010	491.2	635.3	324.5	284.0	1735.0
2011	444.2	543.8	344.3	271.0	1603.3
2012	410.9	358.2	*335*	*395.9*	*1500*
2013	*420*	*540*	*330*	*260*	*1550*

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	1.42	1.40	.31	d.22	2.92
2010	1.03	1.26	.21	d.07	2.43
2011	1.05	1.25	.69	d.13	2.86
2012	1.12	1.32	*.30*	*d.19*	*2.55*
2013	*1.10*	*1.35*	*.40*	*d.15*	*2.70*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.375	.375	.375	.375	1.50
2009	.385	.385	.385	.385	1.54
2010	.395	.395	.395	.395	1.58
2011	.405	.405	.405	.405	1.62
2012	.415	.415			

BUSINESS: Laclede Group, Inc., is a holding company for Laclede Gas, which distributes natural gas in eastern Missouri, including the city of St. Louis, St. Louis County, and parts of 10 other counties. Has roughly 625,000 customers. Purchased SM&P Utility Resources, 1/02; divested, 3/08. Utility therms sold and transported in fiscal 2011: 1.1 bill. Revenue mix for regulated operations: residential, 64; commercial and industrial, 22%; transportation, 2%; other, 12%. Has around 1,640 employees. Officers and directors own approximately 8% of common shares (1/12 proxy). Chairman: William E. Nasser; CEO: Suzanne Sitherwood. Incorporated: Missouri. Address: 720 Olive Street, St. Louis, Missouri 63101. Telephone: 314-342-0500. Internet: www.thelacledegroup.com.

Laclede Group had a successful second quarter, with a bottom-line advance of 6% over the same period in 2011. That said, as a result of a rise in pension and benefit expenses, we do anticipate weak comparisons in the third and fourth quarters, and have lowered our 2012 estimate by $0.15, to $2.55, accordingly.

The company has decided on several growth initiatives under the guidance of its new CEO, Suzanne Sitherwood. Goals include developing and investing in emerging technologies, growth via acquisitions, infrastructure investments, and boosting the core business. Investors should note that growing via acquisitions, as well as focusing on research and development, would be major changes from Laclede's previous path. Management has also restructured part of its transportation agreements, as well as entered the storage market (though the glut in natural gas supply could limit profits from this sector). As the increase in the customer base has been sluggish and the service sector continues to stagnate, any new ventures could provide the company with a nice boost in revenues and earnings for the 2015-2017 period, if successfully pulled off.

Laclede filed a request with the Missouri Public Service Commission regarding its infrastructure system replacement surcharge (ISRS). The surcharge is part of the costs the company must incur to maintain and upgrade its systems, and concerns expenses related to its 16,000 miles of pipeline. Laclede has asked the commission to increase its ISRS by over $3 million (raising customer bills by $0.38 a month), which, if successful, should provide a modest boost to profits for the year.

The stock's dividend yield, at over 4%, is a notch above the industry average. Given LG's history, future payout hikes are also likely, though they are slated to be moderate (a result of probable lukewarm earnings growth).

Long-term potential is unexciting. The equity is trading close to our 3- to 5-year Target Price Range, discounting much of its appreciation potential. However, given the good Safety rank and the rich yield, conservative, income-oriented investors might have some interest here.

Sahana Zutshi *June 8, 2012*

(A) Fiscal year ends Sept. 30th.
(B) Based on average shares outstanding thru. '97, then diluted. Excludes nonrecurring loss: '06, 7¢. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late July. **(C)** Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available. **(D)** Incl. deferred charges. In '11: $429.9 mill., $19.17/sh. **(E)** In millions. **(F)** Qtly. egs. may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	80

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NEW JERSEY RES. NYSE-NJR

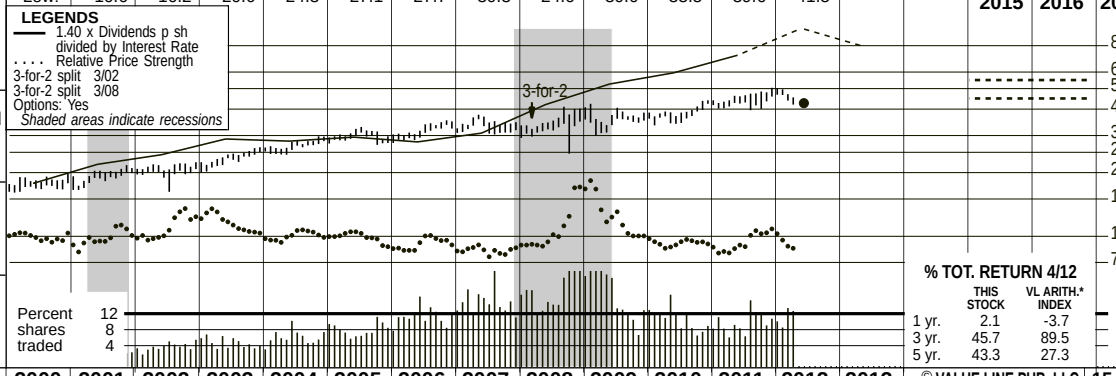
RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
42.62	14.6	(Trailing: 13.6 Median: 15.0)	1.01	3.6%	VALUE LINE

TIMELINESS 3 Raised 2/17/12
SAFETY 1 Raised 9/15/06
TECHNICAL 3 Raised 4/27/12
BETA .65 (1.00 = Market)

High:	21.7	22.4	26.4	29.7	32.9	35.4	37.6	41.1	42.4	44.1	50.5	50.3
Low:	16.6	16.2	20.0	24.3	27.1	27.7	30.3	24.6	30.0	33.5	39.6	41.5

Target Price Range
2015 | 2016 | 2017

LEGENDS
— 1.40 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 3/02
3-for-2 split 3/08
Options: Yes
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+30%)	*10%*
Low	45	(+5%)	*5%*

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	1	0
Options	0	1	0	0	0	0	0	1	0
to Sell	0	2	0	0	0	0	0	2	0

Institutional Decisions

	2Q2011	3Q2011	4Q2011
to Buy	58	69	66
to Sell	67	58	65
Hld's(000)	23841	23955	24285

% TOT. RETURN 4/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	2.1	-3.7
3 yr.	45.7	89.5
5 yr.	43.3	27.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
13.48	17.31	17.73	22.65	29.42	51.22	44.11	62.29	60.89	76.19	79.63	72.62	90.74	62.34	64.10	72.60	*67.50*	*80.00*	Revenues per sh A	*87.25*
1.48	1.63	1.74	1.86	1.99	2.12	2.14	2.38	2.50	2.62	2.73	2.44	3.62	3.16	3.26	3.40	*3.85*	*4.10*	"Cash Flow" per sh	*4.50*
.92	.99	1.04	1.11	1.20	1.30	1.39	1.59	1.70	1.77	1.87	1.55	2.70	2.40	2.46	2.58	*2.85*	*3.15*	Earnings per sh B	*3.45*
.69	.71	.73	.75	.76	.78	.80	.83	.87	.91	.96	1.01	1.11	1.24	1.36	1.44	*1.52*	*1.52*	Div'ds Decl'd per sh C■	*1.68*
1.19	1.15	1.07	1.21	1.23	1.10	1.02	1.14	1.45	1.28	1.28	1.46	1.72	1.81	2.10	2.26	*2.00*	*2.00*	Cap'l Spending per sh	*2.00*
6.73	6.92	7.26	7.57	8.29	8.80	8.71	10.26	11.25	10.60	15.00	15.50	17.28	16.59	17.62	18.73	*18.20*	*19.30*	Book Value per sh D	*24.60*
40.69	40.23	40.07	39.92	39.59	40.00	41.50	40.85	41.61	41.32	41.44	41.61	42.06	41.59	41.17	41.45	*40.00*	*40.00*	Common Shs Outst'g E	*40.00*
13.6	13.5	15.3	15.2	14.7	14.2	14.7	14.0	15.3	16.8	16.1	21.6	12.3	14.9	15.0	16.8	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.85	.78	.80	.87	.96	.73	.80	.80	.81	.89	.87	1.15	.74	.99	.95	1.05	*Value Line*		Relative P/E Ratio	*.95*
5.6%	5.3%	4.6%	4.5%	4.4%	4.2%	3.9%	3.7%	3.3%	3.1%	3.2%	3.0%	3.3%	3.5%	3.7%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 3/31/12
Total Debt $628.9 mill. **Due in 5 Yrs** $129.1 mill.
LT Debt $429.5 mill. **LT Interest** $19.6 mill.
Incl. $69.9 mill. capitalized leases.
(LT interest earned: 7.5x; total interest coverage: 7.5x)
Pension Assets-9/11 $155.7 mill. **Oblig.** $270.2 mill.
Pfd Stock None

Common Stock 41,551,934 shs.
as of 4/30/12
MARKET CAP: $1.8 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
1830.8	2544.4	2533.6	3148.3	3299.6	3021.8	3816.2	2592.5	2639.3	3009.2	*2700*	*3200*	Revenues ($mill) A	*3490*
56.8	65.4	71.6	74.4	78.5	65.3	113.9	101.0	101.8	106.5	*115*	*125*	Net Profit ($mill)	*140*
38.7%	39.4%	39.1%	39.1%	38.9%	38.8%	37.8%	27.1%	41.4%	30.2%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
3.1%	2.6%	2.8%	2.4%	2.4%	2.2%	3.0%	3.9%	3.9%	3.5%	*4.0%*	*3.9%*	Net Profit Margin	*4.0%*
50.6%	38.1%	40.3%	42.0%	34.8%	37.3%	38.5%	39.8%	37.2%	35.5%	*40.5%*	*39.5%*	Long-Term Debt Ratio	*33.5%*
49.4%	61.9%	59.7%	58.0%	65.2%	62.7%	61.5%	60.2%	62.8%	64.5%	*59.5%*	*60.5%*	Common Equity Ratio	*66.5%*
732.4	676.8	783.8	755.3	954.0	1028.0	1182.1	1144.8	1154.4	1203.1	*1230*	*1275*	Total Capital ($mill)	*1480*
756.4	852.6	880.4	905.1	934.9	970.9	1017.3	1064.4	1135.7	1295.9	*1320*	*1350*	Net Plant ($mill)	*1430*
8.7%	10.7%	10.1%	11.2%	9.6%	7.7%	10.7%	9.7%	9.7%	9.7%	*10.5%*	*11.0%*	Return on Total Cap'l	*10.5%*
15.7%	15.6%	15.3%	17.0%	12.6%	10.1%	15.7%	14.6%	14.0%	13.7%	*16.0%*	*16.5%*	Return on Shr. Equity	*14.0%*
15.7%	15.6%	15.3%	17.0%	12.6%	10.1%	15.7%	14.6%	14.0%	13.7%	*16.0%*	*16.5%*	Return on Com Equity	*14.0%*
6.9%	7.7%	7.8%	8.5%	6.3%	3.6%	9.5%	7.2%	6.7%	6.2%	*7.5%*	*8.5%*	Retained to Com Eq	*7.5%*
56%	51%	49%	50%	50%	64%	40%	50%	52%	55%	*53%*	*49%*	All Div'ds to Net Prof	*48%*

CURRENT POSITION ($MILL.)	2010	2011	3/31/12
Cash Assets	.9	7.4	7.8
Other	784.1	725.0	666.9
Current Assets	785.0	732.4	674.7
Accts Payable	47.3	66.0	63.3
Debt Due	178.9	166.9	199.4
Other	479.6	470.5	371.5
Current Liab.	705.8	703.4	634.2
Fix. Chg. Cov.	700%	700%	700%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	7.0%	-1.5%	*4.5%*
"Cash Flow"	5.0%	4.5%	*5.5%*
Earnings	7.5%	7.0%	*5.5%*
Dividends	6.0%	8.0%	*4.0%*
Book Value	8.0%	7.5%	*5.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	801.3	937.5	441.1	412.6	2592.5
2010	609.6	918.4	479.8	631.5	2639.3
2011	713.2	977.0	648.1	670.9	3009.2
2012	642.4	612.9	*710*	*734.7*	*2700*
2013	*685*	*1050*	*720*	*745*	*3200*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	.77	1.71	.03	d.12	2.40
2010	.66	1.55	.28	d.03	2.46
2011	.71	1.62	.23	.02	2.58
2012	1.09	1.79	*.10*	*d.13*	*2.85*
2013	*1.15*	*1.67*	*.28*	*.05*	*3.15*

Cal-endar	QUARTERLY DIVIDENDS PAID C E■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.267	.28	.28	.28	1.11
2009	.31	.31	.31	.31	1.24
2010	.34	.34	.34	.34	1.36
2011	.36	.36	.36	.36	1.44
2012	.38	.38			

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in New Jersey, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had about 494,964 customers at 9/30/11 in Monmouth and Ocean Counties, and other N.J. Counties. Fiscal 2011 volume: 178 bill. cu. ft. (5% interruptible, 35% residential and commercial and electric utility, 60% incentive programs). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2011 dep. rate: 2.2%. Has 891 empls. Off./dir. own about 1.1% of common (12/11 Proxy). Chrmn., CEO & Pres. : Laurence M. Downes. Inc.: NJ Addr.: 1415 Wyckoff Road, Wall, NJ 07719. Tel.: 732-938-1480. Web: www.njresources.com.

New Jersey Resources posted a mixed bag of financial results for the March quarter. Indeed, quarterly revenues declined about 37% on a year-over-year basis. However, this trend resulted from the continued decline in natural gas pricing that has been going on since the middle of 2011. However, that downturn began to reverse in April, and higher natural gas prices should persist through the third quarter and possibly beyond. Meanwhile, the New Jersey Natural Gas (NJNG) division added 1,491 customers during the period, bringing this year's total to 3,292. On the profitability front, overall operating expenses declined 150 basis points as a percentage of the top line. On balance, the bottom line increased 10.5%, to $1.79 a share, which was higher than expected.

Still, we have left our 2012 earnings estimate unchanged for the time being. Based on management's reiteration of its guidance, we look for the second half of the fiscal year (the slow season) to prove quite challenging. That said, the company is still on pace to log a nice double-digit share-net advance this year. We expect that trend to continue as the company completes multiple capital projects (see below), and adds a projected 12,000 to 14,000 new NJNG customers during fiscal 2012 and 2013, combined.

NJR Clean Energy Ventures (NJRCEV) continues to make progress this year. That unit doubled its contribution to net income during the March period. Thus far in 2012, NJRCEV has completed and placed into service four different solar facilities, amounting to 23.7 megawatts worth of generation capacity. Additionally, that unit has signed on to invest $20 million in a new 6.7 megawatt, ground-mounted solar project in Medford, NJ, to supply power to the grid. That capital development is anticipated to be in service in the first quarter of 2013.

Since our March review, these shares have logged a price correction of about 9%. This may afford an attractive entry point for income-seeking investors, as NJR offers a solid dividend yield. However, investors should note that the median yield for all utilities covered in this Issue is about 3.9%, leaving this particular stock slightly below average.

Bryan J. Fong *June 8, 2012*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly egs may not sum to total due to change in shares outstanding. Next earnings report due late July.
(C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2011: $434.2 million, $10.49/share.
(E) In millions, adjusted for splits.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	50

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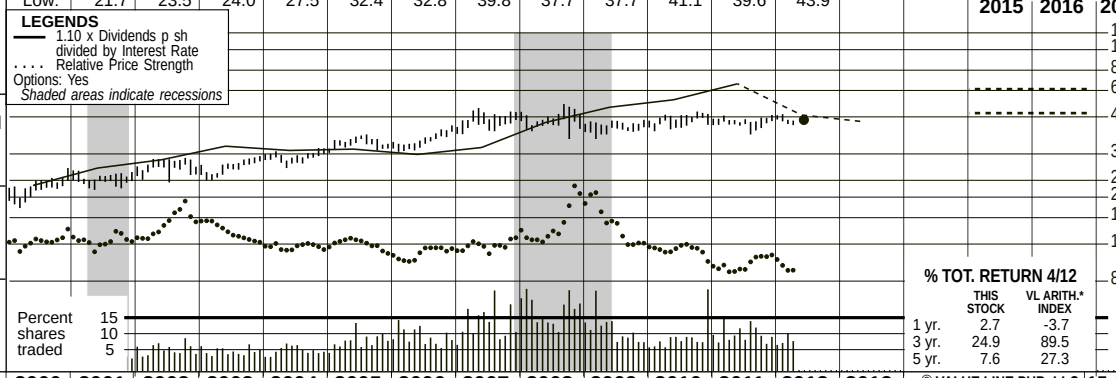
N.W. NAT'L GAS NYSE-NWN

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
46.38	18.6	(Trailing: 19.6 Median: 17.0)	1.29	3.8%	VALUE LINE

TIMELINESS 4 Lowered 5/13/11
SAFETY 1 Raised 3/18/05
TECHNICAL 3 Raised 5/11/12
BETA .60 (1.00 = Market)

High:	26.8	30.7	31.3	34.1	39.6	43.7	52.8	55.2	46.5	50.9	49.0	49.5
Low:	21.7	23.5	24.0	27.5	32.4	32.8	39.8	37.7	37.7	41.1	39.6	43.9

Target Price Range
2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+40%)	12%
Low	50	(+10%)	6%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	1	0	0	0	0	0	0	0
Options	0	0	0	0	1	0	0	0	1
to Sell	0	0	1	0	2	0	2	0	1

Institutional Decisions

	2Q2011	3Q2011	4Q2011
to Buy	54	54	72
to Sell	65	66	43
Hld's(000)	15895	16264	16071

% TOT. RETURN 4/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	2.7	-3.7
3 yr.	24.9	89.5
5 yr.	7.6	27.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
16.86	15.82	16.77	18.17	21.09	25.78	25.07	23.57	25.69	33.01	37.20	39.13	39.16	38.17	30.56	31.72	32.20	32.15	Revenues per sh	41.95
3.86	3.72	3.24	3.72	3.68	3.86	3.65	3.85	3.92	4.34	4.76	5.41	5.31	5.20	5.18	5.00	5.30	5.55	"Cash Flow" per sh	6.45
1.97	1.76	1.02	1.70	1.79	1.88	1.62	1.76	1.86	2.11	2.35	2.76	2.57	2.83	2.73	2.39	2.50	2.70	Earnings per sh A	3.40
1.20	1.21	1.22	1.23	1.24	1.25	1.26	1.27	1.30	1.32	1.39	1.44	1.52	1.60	1.68	1.75	1.78	1.82	Div'ds Decl'd per sh B■	1.94
3.70	5.07	4.02	4.78	3.46	3.23	3.11	4.90	5.52	3.48	3.56	4.48	3.92	5.09	9.35	3.76	2.95	3.55	Cap'l Spending per sh	7.10
15.37	16.02	16.59	17.12	17.93	18.56	18.88	19.52	20.64	21.28	22.01	22.52	23.71	24.88	26.08	26.70	27.80	28.25	Book Value per sh D	29.10
22.56	22.86	24.85	25.09	25.23	25.23	25.59	25.94	27.55	27.58	27.24	26.41	26.50	26.53	26.58	26.76	27.00	28.00	Common Shs Outst'g C	31.00
11.7	14.4	26.7	14.5	12.4	12.9	17.2	15.8	16.7	17.0	15.9	16.7	18.1	15.2	17.0	19.0	Bold figures are		Avg Ann'l P/E Ratio	17.0
.73	.83	1.39	.83	.81	.66	.94	.90	.88	.91	.86	.89	1.09	1.01	1.08	1.20	Value Line		Relative P/E Ratio	1.15
5.2%	4.8%	4.5%	5.0%	5.6%	5.1%	4.5%	4.6%	4.2%	3.7%	3.7%	3.1%	3.3%	3.7%	3.6%	3.9%	estimates		Avg Ann'l Div'd Yield	3.3%

CAPITAL STRUCTURE as of 3/31/12
Total Debt $755.4 mill. **Due in 5 Yrs** $200 mill.
LT Debt $641.7 mill. **LT Interest** $45.0 mill.

(Total interest coverage: 7.0x)

Pension Assets-12/10 $219 mill. **Oblig.** $337.3 mill.

Pfd Stock None

Common Stock 26,800,474 shares

MARKET CAP $1.2 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
641.4	611.3	707.6	910.5	1013.2	1033.2	1037.9	1012.7	812.1	848.8	870	900	Revenues ($mill)	1300
43.8	46.0	50.6	58.1	65.2	74.5	68.5	75.1	72.7	63.9	67.5	75.5	Net Profit ($mill)	105
34.9%	33.7%	34.4%	36.0%	36.3%	37.2%	36.9%	38.3%	40.5%	40.4%	30.0%	30.0%	Income Tax Rate	30.0%
6.8%	7.5%	7.1%	6.4%	6.4%	7.2%	6.6%	7.4%	8.9%	7.5%	7.8%	8.4%	Net Profit Margin	8.1%
47.6%	49.7%	46.0%	47.0%	46.3%	46.3%	44.9%	47.7%	46.1%	47.3%	45%	43%	Long-Term Debt Ratio	37%
51.5%	50.3%	54.0%	53.0%	53.7%	53.7%	55.1%	52.3%	53.9%	52.7%	55%	57%	Common Equity Ratio	63%
937.3	1006.6	1052.5	1108.4	1116.5	1106.8	1140.4	1261.8	1284.8	1356.2	1370	1390	Total Capital ($mill)	1440
995.6	1205.9	1318.4	1373.4	1425.1	1495.9	1549.1	1670.1	1854.2	1893.9	1955	2030	Net Plant ($mill)	2300
5.9%	5.7%	5.9%	6.5%	7.1%	8.5%	7.7%	7.3%	7.0%	6.2%	6.5%	7.0%	Return on Total Cap'l	8.5%
8.9%	9.1%	8.9%	9.9%	10.9%	12.5%	10.9%	11.4%	10.5%	8.9%	9.0%	9.5%	Return on Shr. Equity	11.5%
8.5%	9.0%	8.9%	9.9%	10.9%	12.5%	10.9%	11.4%	10.5%	8.9%	9.0%	9.5%	Return on Com Equity	11.5%
1.9%	2.6%	2.7%	3.7%	4.5%	6.0%	4.5%	5.0%	4.0%	2.4%	2.5%	3.0%	Retained to Com Eq	5.0%
79%	72%	69%	63%	59%	52%	59%	56%	61%	73%	71%	67%	All Div'ds to Net Prof	57%

CURRENT POSITION ($MILL.)	2010	2011	3/31/12
Cash Assets	3.5	5.8	4.0
Other	326.8	342.9	306.9
Current Assets	330.3	348.7	310.9
Accts Payable	93.2	86.3	60.2
Debt Due	267.4	181.6	113.7
Other	107.6	146.6	166.7
Current Liab.	468.2	414.5	340.6
Fix. Chg. Cov.	366%	334%	363%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	4.5%	1.0%	4.5%
"Cash Flow"	3.0%	3.5%	4.5%
Earnings	4.0%	4.5%	4.0%
Dividends	3.0%	4.5%	3.0%
Book Value	4.0%	4.0%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	437.4	149.1	116.9	309.3	1012.7
2010	286.5	162.4	95.1	268.1	812.1
2011	323.1	161.2	93.3	271.2	848.8
2012	317.5	160	100	292.5	870
2013	330	170	150	250	900

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1.78	.12	d.25	1.18	2.83
2010	1.64	.26	d.28	1.11	2.73
2011	1.53	.08	d.31	1.09	2.39
2012	1.51	.15	d.50	1.34	2.50
2013	1.75	.15	d.30	1.10	2.70

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.375	.375	.375	.395	1.52
2009	.395	.395	.395	.415	1.60
2010	.415	.415	.415	.435	1.68
2011	.435	.435	.435	.445	1.75
2012	.445	.445			

BUSINESS: Northwest Natural Gas Co. distributes natural gas to 90 communities, 668,000 customers, in Oregon (90% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 2.5 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 57%; commercial, 26%; industrial, gas transportation, and other, 17%. Employs 1,061. BlackRock Inc. owns 7.8% of shares; officers and directors, 1.7% (4/12 proxy). CEO: Gregg S. Kantor. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Telephone: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural Gas' profit is slated to modestly advance in 2012, despite higher-than-expected operational expenses. That said, revenue and earnings pulled back marginally in the first quarter, falling roughly 1% from the like period last year. As a result, we have decided to lower our 2012 and 2013 share-net estimates by $0.15 and $0.25, to $2.50 and $2.70, respectively.

The company continues to be active in Oregon. Along with its rate case (filed at the end of 2011, asking for a 6% rate increase), it is filing tariffs with the Oregon Public Utility Commission, as well as the Washington Utilities of Transportation Commission, for a refund of about $39 million (in gas cost savings to customers). Northwest Natural also filed a request with OPUC to provide Oregon customers with an additional $9 million in savings. All in all, management hopes these measures will strengthen the profitabilty in Oregon, enabling it to accelerate its bottom line growth.

Customer demand is growing modestly, but steadily. Residential and commercial customer count rose 1% in the March term, year over year, but industrial customer demand increased over 4% for the same period. The company hopes that the gain in customers (it added several new accounts in the forest products segment, and hopes to add more in the asphalt plant business as the year goes on) will help offset minor losses from low gas prices (via its storage segment).

Major projects are proceeding on schedule. The Encana venture is scheduled to begin operations by mid-decade, and is proceeding without obstacles thus far (24 new wells are likely to be drilled by the end of the year, with about 28% of the total investment of $250 million completed). The Gill Ranch expansion is also on track, and should considerably boost volume from 2013 onward. Both ventures should bolster the top and bottom lines, though we remain skeptical of their ability to fully offset the negative impact of a lukewarm economy.

We would pass on this untimely issue. This equity has subpar long-term appreciation potential, and its dividend yield is about in line with the industry average.

Sahana Zutshi *June 8, 2012*

(A) Diluted earnings per share. Excludes nonrecurring items: '98, $0.15; '00, $0.11; '06, ($0.06); '08, ($0.03); '09, 6¢. Next earnings report due late July.

(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.

(D) Includes Intangibles. In 2011: $371.4 million. $13.90/share.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	90

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PIEDMONT NAT'L. GAS NYSE-PNY

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
29.87	17.8	(Trailing: 20.5 Median: 18.0)	1.24	4.0%	VALUE LINE

TIMELINESS 4 Lowered 3/23/12
SAFETY 2 New 7/27/90
TECHNICAL 3 Raised 5/11/12
BETA .70 (1.00 = Market)

High:	19.0	19.0	22.0	24.3	25.8	28.4	28.0	35.3	32.0	30.1	34.7	34.6
Low:	14.6	13.7	16.6	19.2	21.3	23.2	22.0	21.7	20.7	23.9	25.9	28.9

Target Price Range
2015 | 2016 | 2017

2015-17 PROJECTIONS

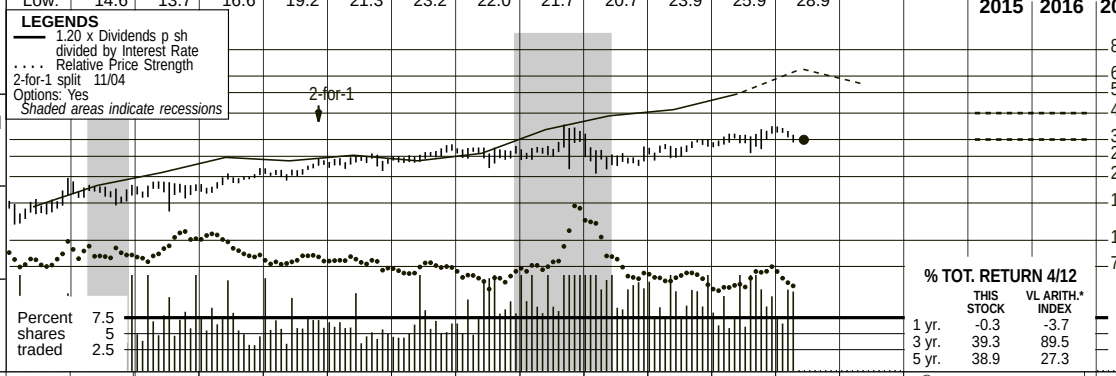
	Price	Gain	Ann'l Total Return
High	40	(+35%)	11%
Low	30	(Nil)	4%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	0	0	0	0	1

Institutional Decisions

	2Q2011	3Q2011	4Q2011
to Buy	70	87	85
to Sell	82	80	85
Hld's(000)	31155	32138	32579



% TOT. RETURN 4/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-0.3	-3.7
3 yr.	39.3	89.5
5 yr.	38.9	27.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
11.59	12.84	12.45	10.97	13.01	17.06	12.57	18.14	19.95	22.96	25.80	23.37	28.52	22.36	21.48	19.83	*19.85*	*22.85*	Revenues per sh A	*25.70*
1.49	1.62	1.72	1.70	1.77	1.81	1.81	2.04	2.31	2.43	2.51	2.64	2.77	3.01	2.91	2.99	*3.00*	*3.20*	"Cash Flow" per sh	*3.45*
.84	.93	.98	.93	1.01	1.01	.95	1.11	1.27	1.32	1.28	1.40	1.49	1.67	1.55	1.57	*1.55*	*1.70*	Earnings per sh AB	*1.85*
.57	.61	.64	.68	.72	.76	.80	.82	.85	.91	.95	.99	1.03	1.07	1.11	1.15	*1.19*	*1.23*	Div'ds Decl'd per sh C■	*1.35*
1.64	1.52	1.48	1.58	1.65	1.29	1.21	1.16	1.85	2.50	2.74	1.85	2.47	1.76	2.75	3.37	*7.75*	*7.85*	Cap'l Spending per sh	*8.10*
6.53	6.95	7.45	7.86	8.26	8.63	8.91	9.36	11.15	11.53	11.83	11.99	12.11	12.67	13.35	13.79	*13.90*	*13.95*	Book Value per sh D	*14.65*
59.10	60.39	61.48	62.59	63.83	64.93	66.18	67.31	76.67	76.70	74.61	73.23	73.26	73.27	72.28	72.32	*71.00*	*70.00*	Common Shs Outst'g E	*68.00*
13.9	13.6	16.3	17.7	14.3	16.7	18.4	16.7	16.6	17.9	19.2	18.7	18.2	15.4	17.1	18.9	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.87	.78	.85	1.01	.93	.86	1.01	.95	.88	.95	1.04	.99	1.10	1.03	1.09	1.19	*Value Line*		Relative P/E Ratio	*1.20*
4.9%	4.8%	4.0%	4.1%	5.0%	4.5%	4.6%	4.4%	4.1%	3.8%	3.9%	3.8%	3.8%	4.1%	4.2%	3.9%	*estimates*		Avg Ann'l Div'd Yield	*3.9%*

CAPITAL STRUCTURE as of 1/31/12
Total Debt $1132.5 mill. **Due in 5 Yrs** $175.0 mill.
LT Debt $675.0 mill. **LT Interest** $46.1 mill.
(LT interest earned: 4.1x; total interest coverage: 3.4x)

Pension Assets-10/11 $259.5 mill. **Oblig.** $236.6 mill.

Pfd Stock None

Common Stock 71,685,958 shs. **as of 3/1/12**

MARKET CAP: $2.1 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
832.0	1220.8	1529.7	1761.1	1924.6	1711.3	2089.1	1638.1	1552.3	1433.9	*1340*	*1600*	Revenues ($mill) A	*1750*
62.2	74.4	95.2	101.3	97.2	104.4	110.0	122.8	111.8	113.6	*110*	*120*	Net Profit ($mill)	*125*
33.1%	34.8%	35.1%	33.7%	34.2%	33.0%	36.3%	28.5%	23.4%	24.6%	*30.0%*	*30.0%*	Income Tax Rate	*30.0%*
7.5%	6.1%	6.2%	5.8%	5.0%	6.1%	5.3%	7.5%	7.2%	7.9%	*8.2%*	*7.5%*	Net Profit Margin	*7.3%*
43.9%	42.2%	43.6%	41.4%	48.3%	48.4%	47.2%	44.1%	41.0%	40.4%	*43.0%*	*46.5%*	Long-Term Debt Ratio	*50.0%*
56.1%	57.8%	56.4%	58.6%	51.7%	51.6%	52.8%	55.9%	59.0%	59.6%	*57.0%*	*53.5%*	Common Equity Ratio	*50.0%*
1051.6	1090.2	1514.9	1509.2	1707.9	1703.3	1681.5	1660.5	1636.9	1671.9	*1730*	*1825*	Total Capital ($mill)	*1990*
1158.5	1812.3	1849.8	1939.1	2075.3	2141.5	2240.8	2304.4	2437.7	2627.3	*2700*	*2750*	Net Plant ($mill)	*2900*
7.8%	8.6%	7.8%	8.2%	7.2%	7.8%	8.2%	9.1%	8.4%	8.2%	*8.0%*	*8.5%*	Return on Total Cap'l	*8.5%*
10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	13.2%	11.6%	11.4%	*11.5%*	*12.0%*	Return on Shr. Equity	*13.0%*
10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	13.2%	11.6%	11.4%	*11.5%*	*12.0%*	Return on Com Equity	*13.0%*
1.7%	3.1%	3.7%	3.6%	2.8%	3.5%	3.9%	4.8%	3.3%	3.1%	*2.5%*	*3.5%*	Retained to Com Eq	*3.5%*
83%	74%	66%	68%	74%	70%	69%	64%	72%	73%	*77%*	*72%*	All Div'ds to Net Prof	*72%*

CURRENT POSITION ($MILL.)	2010	2011	1/31/12
Cash Assets	5.6	6.8	10.1
Other	322.2	279.2	420.2
Current Assets	327.8	286.0	430.3
Accts Payable	115.7	129.7	135.3
Debt Due	302.0	331.0	457.5
Other	80.9	72.9	99.2
Current Liab.	498.6	534.1	692.0
Fix. Chg. Cov.	323%	323%	325%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	4.5%	-1.5%	*3.5%*
"Cash Flow"	5.5%	4.0%	*2.5%*
Earnings	5.0%	4.5%	*2.5%*
Dividends	4.5%	4.0%	*3.5%*
Book Value	5.0%	3.0%	*1.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2009	779.6	455.4	180.3	222.8	1638.1
2010	673.7	472.9	211.6	194.1	1552.3
2011	652.0	392.6	197.3	192.0	1433.9
2012	471.8	*415*	*225*	*228.2*	*1340*
2013	*535*	*480*	*290*	*295*	*1600*

Fiscal Year Ends	EARNINGS PER SHARE A B Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2009	1.10	.73	d.10	d.06	1.67
2010	1.14	.65	d.13	d.13	1.55
2011	1.16	.66	d.12	d.13	1.57
2012	1.05	*.70*	*d.10*	*d.10*	*1.55*
2013	*1.18*	*.70*	*d.09*	*d.09*	*1.70*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.25	.26	.26	.26	1.03
2009	.26	.27	.27	.27	1.07
2010	.27	.28	.28	.28	1.11
2011	.28	.29	.29	.29	1.15
2012	.29	.30			

BUSINESS: Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 968,188 customers in North Carolina, South Carolina, and Tennessee. 2011 revenue mix: residential (46%), commercial (27%), industrial (7%), other (20%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 60.0% of revenues. '11 deprec. rate: 3.2%. Estimated plant age: 10 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has about 1,782 employees. Off./dir. own about 1.2% of common stock, BlackRock; 7.6% (1/12 proxy). Chrmn., CEO, & Pres.: Thomas E. Skains. Inc.: NC. Addr.: 4720 Piedmont Row Drive, Charlotte, NC 28210. Telephone: 704-364-3120. Internet: www.piedmontng.com.

Piedmont Natural Gas posted lower-than-expected financial results for the first quarter of fiscal 2012 (ended January 31st). Warmer weather than normal versus the prior year was a factor. Elsewhere, on the profitability front, operating expenses increased as a percentage of the top line by 740 basis points. Additional detractors stemmed from lower "other" income, particularly from PNY's stakes in equity-method investments. On balance, the bottom line declined about 9.5%, to $1.05 a share. Consequently,

We have trimmed a dime off our 2012 share-net estimate. The diminished top line can largely be viewed as a technicality, because utility companies pass the cost of gas through to the end-use customers. However, the margin compression, and weakness in other income, will likely result in a slight, low single-digit earnings decline this year.

But bottom line gains may resume next year. This ought to be supported by additions in the company's residential and commercial customers, thanks to new construction in those markets. New power generation customers will be added when construction is completed on a pair of projects. One is due to come on line this month, and the other a year from now.

Meanwhile, the balance sheet continues to improve. During the first quarter, cash reserves increased almost 50%. That financial cushion now sits at roughly $10.1 million. At the same time, the long-term debt load has remained constant at about 40% of the total capital structure and should be well within manageable levels. In fact, that form of funding has been on the decline since the middle of the last decade. What's more, the board recently approved a hike in the quarterly dividend of 3.4%, to $0.30 a share.

These shares have logged a price correction of about 9.5% since our March review. In comparison, the S&P 500 Index declined only about 4% for that same interim. This move is in contrast to what we would expect from a stock with a below-market Beta.

Still, at its present quotation, the untimely stock may appeal to income-oriented investors, thanks to its slightly above-average dividend yield.

Bryan J. Fong *June 8, 2012*

(A) Fiscal year ends October 31st.
(B) Diluted earnings. Excl. extraordinary item: '00, 8¢. Excl. nonrecurring gains (losses): '97, (2¢); '10, 41¢. Next earnings report due mid June. Quarters may not add to total due to change in shares outstanding.
(C) Dividends historically paid early-January, April, July, October.
■ Div'd reinvest. plan available; 5% discount.
(D) Includes deferred charges. In 2011: $527.6 million, $7.29/share.
(E) In millions, adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	95

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SOUTH JERSEY INDS. NYSE-SJI

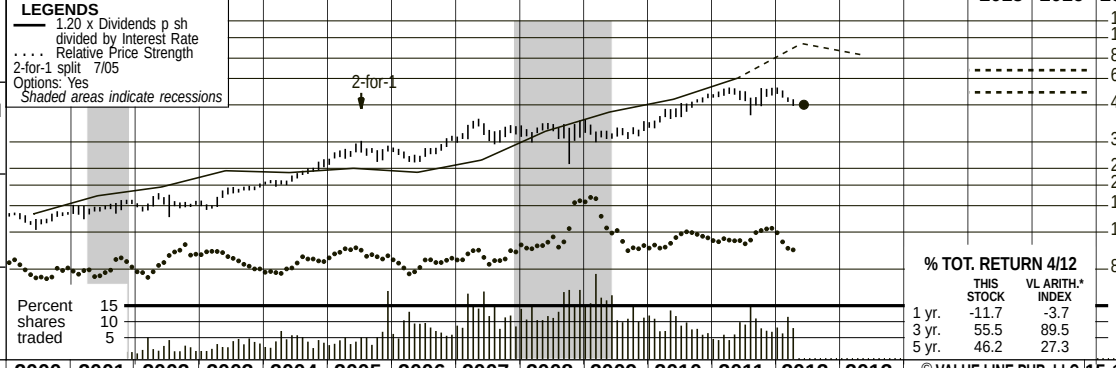
RECENT PRICE **47.96** | P/E RATIO **15.5** (Trailing: 16.5 / Median: 15.0) | RELATIVE P/E RATIO **1.08** | DIV'D YLD **3.5%** | VALUE LINE

TIMELINESS 3 Raised 3/9/12
SAFETY 2 Lowered 1/4/91
TECHNICAL 3 Lowered 9/2/11
BETA .65 (1.00 = Market)

High:	17.0	18.3	20.3	26.5	32.4	34.3	41.3	40.6	40.8	54.2	58.0	58.0
Low:	13.8	14.1	15.3	19.7	24.9	25.6	31.2	25.2	32.0	37.2	42.8	46.5

Target Price Range
2015 | 2016 | 2017

LEGENDS
— 1.20 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 7/05
Options: Yes
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+45%)	13%
Low	55	(+15%)	7%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	2	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	2	0	0	0	0	0	0	3

Institutional Decisions

	2Q2011	3Q2011	4Q2011
to Buy	64	68	59
to Sell	73	66	60
Hld's(000)	17547	17887	17847

% TOT. RETURN 4/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-11.7	-3.7
3 yr.	55.5	89.5
5 yr.	46.2	27.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
16.52	16.18	20.89	17.60	22.43	35.30	20.69	26.34	29.51	31.78	31.76	32.30	32.36	28.37	30.97	27.42	*27.75*	*29.70*	Revenues per sh	*36.55*
1.54	1.60	1.44	1.84	1.95	1.90	2.12	2.24	2.44	2.51	3.51	3.20	3.48	3.72	4.21	4.46	*4.50*	*5.00*	"Cash Flow" per sh	*6.20*
.85	.86	.64	1.01	1.08	1.15	1.22	1.37	1.58	1.71	2.46	2.09	2.27	2.38	2.70	2.89	*3.10*	*3.40*	Earnings per sh A	*4.50*
.72	.72	.72	.72	.73	.74	.75	.78	.82	.86	.92	1.01	1.11	1.22	1.36	1.50	*1.64*	*1.78*	Div'ds Decl'd per sh B ■	*2.25*
2.01	2.30	3.06	2.19	2.21	2.82	3.47	2.36	2.67	3.21	2.51	1.88	2.08	3.67	5.59	6.39	*6.15*	*6.55*	Cap'l Spending per sh	*7.45*
8.03	6.43	6.23	6.74	7.25	7.81	9.67	11.26	12.41	13.50	15.11	16.25	17.33	18.24	19.08	20.66	*23.40*	*25.00*	Book Value per sh C	*28.55*
21.51	21.54	21.56	22.30	23.00	23.72	24.41	26.46	27.76	28.98	29.33	29.61	29.73	29.80	29.87	30.21	*31.00*	*32.00*	Common Shs Outst'g D	*35.00*
13.3	13.8	21.2	13.3	13.0	13.6	13.5	13.3	14.1	16.6	11.9	17.2	15.9	15.0	16.8	18.4	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.83	.80	1.10	.76	.85	.70	.74	.76	.74	.88	.64	.91	.96	1.00	1.07	1.16	*Value Line*		Relative P/E Ratio	*.95*
6.4%	6.1%	5.3%	5.4%	5.2%	4.7%	4.6%	4.3%	3.7%	3.0%	3.2%	2.8%	3.1%	3.4%	3.0%	2.8%	*estimates*		Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 3/31/12
Total Debt $771.1 mill. **Due in 5 Yrs** $438.3 mill.
LT Debt $426.4 mill. **LT Interest** $16.0 mill.
(Total interest coverage: 5.6x)

Pension Assets-12/11 $116.7 mill. **Oblig.** $195.0 mill.

Pfd Stock None

Common Stock 30,400,671 common shs. **as of 5/1/12**

MARKET CAP: $1.5 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
505.1	696.8	819.1	921.0	931.4	956.4	962.0	845.4	925.1	828.6	*860*	*950*	Revenues ($mill)	*1280*
29.4	34.6	43.0	48.6	72.0	61.8	67.7	71.3	81.0	87.0	*95.0*	*110*	Net Profit ($mill)	*155*
41.4%	40.6%	40.9%	41.5%	41.3%	41.9%	47.7%	23.0%	15.2%	22.4%	*25.0%*	*28.0%*	Income Tax Rate	*30.0%*
5.8%	5.0%	5.2%	5.3%	7.7%	6.5%	7.0%	8.4%	8.8%	10.5%	*11.0%*	*11.6%*	Net Profit Margin	*12.1%*
53.6%	50.8%	48.7%	44.9%	44.7%	42.7%	39.2%	36.5%	37.4%	40.5%	*38.5%*	*37.5%*	Long-Term Debt Ratio	*37.5%*
46.1%	49.0%	51.0%	55.1%	55.3%	57.3%	60.8%	63.5%	62.6%	59.5%	*61.5%*	*62.5%*	Common Equity Ratio	*62.5%*
512.5	608.4	675.0	710.3	801.1	839.0	848.0	856.4	910.1	1048.3	*1175*	*1280*	Total Capital ($mill)	*1600*
666.6	748.3	799.9	877.3	920.0	948.9	982.6	1073.1	1193.3	1352.4	*1450*	*1550*	Net Plant ($mill)	*1850*
7.6%	7.3%	7.9%	8.3%	10.1%	8.6%	8.9%	9.0%	9.5%	8.9%	*9.0%*	*9.5%*	Return on Total Cap'l	*10.5%*
12.4%	11.5%	12.4%	12.4%	16.3%	12.8%	13.1%	13.1%	14.2%	13.9%	*13.0%*	*14.0%*	Return on Shr. Equity	*15.5%*
12.5%	11.6%	12.5%	12.4%	16.3%	12.8%	13.1%	13.1%	14.2%	13.9%	*13.0%*	*14.0%*	Return on Com Equity	*15.5%*
4.7%	5.0%	5.9%	6.2%	10.2%	6.7%	6.7%	6.4%	7.1%	6.7%	*6.0%*	*6.5%*	Retained to Com Eq	*7.5%*
62%	57%	52%	50%	37%	48%	49%	51%	50%	52%	*54%*	*52%*	All Div'ds to Net Prof	*51%*

CURRENT POSITION ($MILL.)	2010	2011	3/31/12
Cash Assets	2.4	7.5	3.5
Other	421.4	333.1	291.1
Current Assets	423.8	340.6	294.6
Accts Payable	165.2	153.7	128.2
Debt Due	362.1	323.6	344.7
Other	113.2	110.7	109.9
Current Liab.	640.5	588.0	582.8
Fix. Chg. Cov.	532%	505%	517%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	1.5%	-1.5%	*4.0%*
"Cash Flow"	8.0%	8.0%	*7.0%*
Earnings	9.5%	7.0%	*9.0%*
Dividends	6.5%	9.5%	*9.0%*
Book Value	10.5%	7.0%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	362.2	134.5	127.1	221.6	845.4
2010	329.3	151.6	160.7	283.5	925.1
2011	331.9	160.5	137.6	198.6	828.6
2012	274.8	*170*	*155*	*260.2*	*860*
2013	*325*	*180*	*170*	*275*	*950*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1.46	.15	d.06	.83	2.38
2010	1.49	.24	.10	.87	2.70
2011	1.63	.20	.01	1.05	2.89
2012	1.65	*.25*	*.08*	*1.12*	*3.10*
2013	*1.75*	*.30*	*.12*	*1.23*	*3.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	- -	.270	.270	.568	1.11
2009	- -	.298	.298	.628	1.22
2010	- -	.330	.330	.695	1.36
2011	- -	.365	.365	.768	1.50
2012	- -	.403			

BUSINESS: South Jersey Industries, Inc. is a holding company. Its subsidiary, South Jersey Gas Co., distributes natural gas to 347,725 customers in New Jersey's southern counties, which covers about 2,500 square miles and includes Atlantic City. Gas revenue mix '11: residential, 41%; commercial, 20%; cogeneration and electric generation, 14%; industrial, 25%. Non-utility operations include: South Jersey Energy, South Jersey Resources Group, Marina Energy, and South Jersey Energy Service Plus. Has 675 employees. Off./dir. control 1.0% of common shares; BlackRock Inc., 7.8% (3/12 proxy). Chrmn. & CEO: Edward Graham. Inc.: NJ. Address: 1 South Jersey Plaza, Folsom, NJ 08037. Telephone: 609-561-9000. Internet: www.sjindustries.com.

Shares of South Jersey Industries have traded lower over the past three months. The company reported a fairly mixed performance for the first quarter. Revenues came in somewhat below the prior-year figure. The utility business reported modest top-line growth. However, this was more than offset by a considerable decline in nonutility revenues. Warmer-than-expected temperatures hurt results in both the retail energy and wholesale commodity marketing businesses. Even so, operating costs declined nicely, and share earnings improved modestly.

We look for solid results from the company's utility operations going forward. South Jersey Gas should continue to experience modest growth in the customer base. Natural gas remains the fuel of choice within the utility's service territory. It ought to further benefit from customer interest in converting to natural gas from other fuel sources. In addition, continued spending on infrastructure projects, approved by the New Jersey Board of Public Utilities (NJBPU), ought to improve service and allow the utility to earn a healthy return on these investments. The company is seeking a longer-term mechanism from the NJBPU to support infrastructure investment from 2013 onward.

The wholesale gas marketing business may well continue to experience headwinds. This includes thin storage spreads and a lack of price volatility. The wholesale business has reduced emphasis on traditional storage and trading strategies in favor of pursuing gas marketing opportunities throughout the northeast region. Meanwhile, the nonutility business should benefit from its pipeline of energy projects, and opportunities in the Marcellus Shale.

This issue remains neutrally ranked for year-ahead relative price performance. Looking further out, we anticipate higher revenues and share earnings for the company by 2015-2017. Moreover, South Jersey earns good marks for Safety, Price Stability, and Earnings Predictability. From the recent quotation, this issue has decent, and relatively well-defined, total return potential for the coming years.

Michael Napoli, CFA *June 8, 2012*

(A) Based on GAAP egs. through 2006, economic egs. thereafter. GAAP EPS: '07, $2.10; '08, $2.58; '09, $1.94; '10, $2.22. Excl. nonrecur. gain (loss): '01, $0.13; '08, $0.31; '09, ($0.44); '10, ($0.47); '11, $0.08. Excl gain (losses) from discont. ops.: '01, ($0.02); '02, ($0.04); '03, ($0.09); '05, ($0.02); '06, ($0.02); '07, $0.01. Next egs. report due in August. (B) Div'ds paid early April, July, Oct., and late Dec. ■ Div. reinvest. plan avail. (C) Incl. reg. assets. In 2011: $315.2 mill., $10.43 per shr. (D) In mill., adj. for split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	90
Earnings Predictability	85

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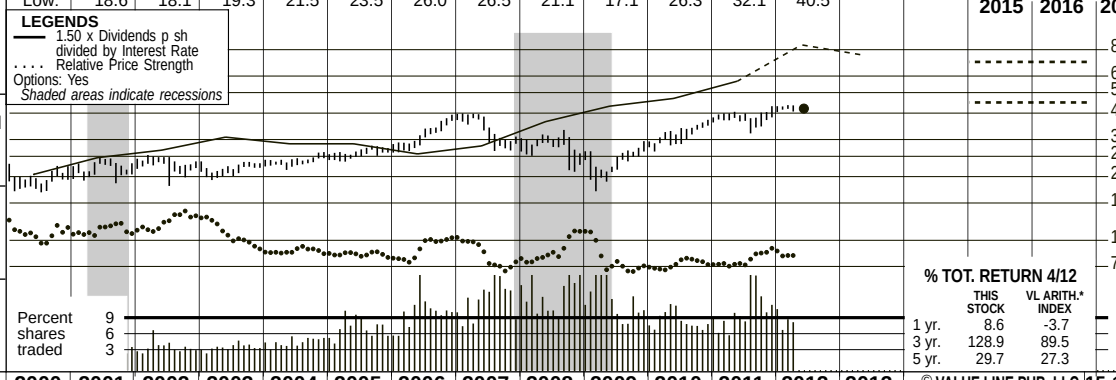
SOUTHWEST GAS NYSE-SWX

RECENT PRICE **42.01** | P/E RATIO **15.6** (Trailing: 15.9 / Median: 17.0) | RELATIVE P/E RATIO **1.08** | DIV'D YLD **2.9%** | **VALUE LINE**

TIMELINESS 1 Raised 5/18/12
SAFETY 3 Lowered 1/4/91
TECHNICAL 3 Raised 5/18/12
BETA .75 (1.00 = Market)

High:	24.7	25.3	23.6	26.2	28.1	39.4	39.9	33.3	29.5	37.3	43.2	43.6
Low:	18.6	18.1	19.3	21.5	23.5	26.0	26.5	21.1	17.1	26.3	32.1	40.5

Target Price Range
2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+65%)	*16%*
Low	45	(+5%)	*5%*

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	1	0	0	2	0	0	0	1
Options	0	0	0	0	1	2	0	0	2
to Sell	0	1	0	0	2	2	1	0	4

Institutional Decisions

	2Q2011	3Q2011	4Q2011
to Buy	76	70	56
to Sell	80	76	95
Hld's(000)	33317	33998	34237

% TOT. RETURN 4/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	8.6	-3.7
3 yr.	128.9	89.5
5 yr.	29.7	27.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
24.09	26.73	30.17	30.24	32.61	42.98	39.68	35.96	40.14	43.59	48.47	50.28	48.53	42.00	40.18	41.07	*40.65*	*40.85*	Revenues per sh	*51.00*
3.00	3.85	4.48	4.45	4.57	4.79	5.07	5.11	5.57	5.20	5.97	6.21	5.76	6.16	6.46	6.81	*7.35*	*7.60*	"Cash Flow" per sh	*9.30*
.25	.77	1.65	1.27	1.21	1.15	1.16	1.13	1.66	1.25	1.98	1.95	1.39	1.94	2.27	2.43	*2.70*	*2.85*	Earnings per sh A	*3.75*
.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.86	.90	.95	1.00	1.06	*1.18*	*1.30*	Div'ds Decl'd per sh B■†	*1.60*
8.19	6.19	6.40	7.41	7.04	8.17	8.50	7.03	8.23	7.49	8.27	7.96	6.79	4.81	4.73	8.29	*8.00*	*8.35*	Cap'l Spending per sh	*9.40*
14.20	14.09	15.67	16.31	16.82	17.27	17.91	18.42	19.18	19.10	21.58	22.98	23.49	24.44	25.62	26.66	*29.80*	*32.30*	Book Value per sh	*37.25*
26.73	27.39	30.41	30.99	31.71	32.49	33.29	34.23	36.79	39.33	41.77	42.81	44.19	45.09	45.56	45.96	*47.00*	*48.00*	Common Shs Outst'g C	*51.00*
69.3	24.1	13.2	21.1	16.0	19.0	19.9	19.2	14.3	20.6	15.9	17.3	20.3	12.2	14.0	15.7	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
4.34	1.39	.69	1.20	1.04	.97	1.09	1.09	.76	1.10	.86	.92	1.22	.81	.89	.99	*Value Line*		Relative P/E Ratio	*1.00*
4.7%	4.4%	3.8%	3.1%	4.2%	3.8%	3.6%	3.8%	3.5%	3.2%	2.6%	2.6%	3.2%	4.0%	3.2%	2.8%	*estimates*		Avg Ann'l Div'd Yield	*2.8%*

CAPITAL STRUCTURE as of 3/31/12
Total Debt $1393.2 mill. **Due in 5 Yrs** $343.0 mill.
LT Debt $1188.1 mill. **LT Interest** $60.0 mill.
(Total interest coverage: 3.8x) (48% of Cap'l)
Leases, Uncapitalized Annual rentals $6.0 mill.
Pension Assets-12/11 $551.8 mill. **Oblig.** $832.8 mill.
Pfd Stock None

Common Stock 46,112,072 shs. **as of 4/27/12**

MARKET CAP: $1.9 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
1320.9	1231.0	1477.1	1714.3	2024.7	2152.1	2144.7	1893.8	1830.4	1887.2	*1910*	*1960*	Revenues ($mill)	*2600*
38.6	38.5	58.9	48.1	80.5	83.2	61.0	87.5	103.9	112.3	*130*	*140*	Net Profit ($mill)	*195*
32.8%	30.5%	34.8%	29.7%	37.3%	36.5%	40.1%	34.0%	34.7%	36.2%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
2.9%	3.1%	4.0%	2.8%	4.0%	3.9%	2.8%	4.6%	5.7%	6.0%	*6.8%*	*7.1%*	Net Profit Margin	*7.5%*
62.5%	66.0%	64.2%	63.8%	60.6%	58.1%	55.3%	53.5%	49.1%	43.2%	*46.0%*	*44.5%*	Long-Term Debt Ratio	*47.0%*
34.1%	34.0%	35.8%	36.2%	39.4%	41.9%	44.7%	46.5%	50.9%	56.8%	*54.0%*	*55.5%*	Common Equity Ratio	*53.0%*
1748.3	1851.6	1968.6	2076.0	2287.8	2349.7	2323.3	2371.4	2291.7	2155.9	*2600*	*2800*	Total Capital ($mill)	*3600*
1979.5	2175.7	2336.0	2489.1	2668.1	2845.3	2983.3	3034.5	3072.4	3218.9	*3300*	*3400*	Net Plant ($mill)	*3750*
4.3%	4.2%	5.0%	4.3%	5.5%	5.5%	4.5%	5.4%	6.1%	6.4%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
5.9%	6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	7.9%	8.9%	9.2%	*9.5%*	*9.0%*	Return on Shr. Equity	*10.5%*
6.5%	6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	7.9%	8.9%	9.2%	*9.5%*	*9.0%*	Return on Com Equity	*10.5%*
1.9%	1.7%	4.3%	2.2%	5.2%	4.8%	2.1%	4.1%	5.1%	5.3%	*5.5%*	*5.0%*	Retained to Com Eq	*6.0%*
70%	72%	49%	65%	42%	44%	63%	48%	43%	43%	*43%*	*45%*	All Div'ds to Net Prof	*42%*

CURRENT POSITION ($MILL.)	2010	2011	3/31/12
Cash Assets	116.1	21.9	218.1
Other	329.8	439.7	367.8
Current Assets	445.9	461.6	585.9
Accts Payable	165.5	186.8	132.5
Debt Due	75.1	322.6	205.1
Other	356.4	338.2	351.7
Current Liab.	597.0	847.6	689.3
Fix. Chg. Cov.	299%	359%	375%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	1.5%	-1.5%	*3.5%*
"Cash Flow"	3.5%	3.0%	*6.0%*
Earnings	6.0%	6.5%	*9.0%*
Dividends	2.0%	4.0%	*8.0%*
Book Value	4.5%	5.0%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	689.9	387.6	317.5	498.8	1893.8
2010	668.8	385.8	307.7	468.1	1830.4
2011	628.4	388.5	352.6	517.7	1887.2
2012	657.6	*390*	*360*	*502.4*	*1910*
2013	*670*	*410*	*370*	*510*	*1960*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1.12	d.01	d.18	1.01	1.94
2010	1.42	d.02	d.11	.98	2.27
2011	1.48	.09	d.34	1.19	2.43
2012	1.70	*.10*	*d.25*	*1.15*	*2.70*
2013	*1.70*	*.15*	*d.20*	*1.20*	*2.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.215	.225	.225	.225	.89
2009	.225	.238	.238	.238	.94
2010	.238	.250	.250	.250	.99
2011	.250	.265	.265	.265	1.05
2012	.265	.295			

BUSINESS: Southwest Gas Corporation is a regulated gas distributor serving approximately 1.9 million customers in sections of Arizona, Nevada, and California. Comprised of two business segments: natural gas operations and construction services. 2011 margin mix: residential and small commercial, 86%; large commercial and industrial, 4%; transportation, 10%. Total throughput: 2.1 billion therms. Sold PriMerit Bank, 7/96. Has 5,754 employees. Off. & Dir. own 1.6% of common stock; BlackRock Inc., 8.5%; GAMCO Investors, Inc., 8.3%; T. Rowe Price Associates, Inc., 6.7% (3/12 Proxy). Chairman: Michael J. Melarkey. CEO: Jeffrey W. Shaw. Inc.: CA. Address: 5241 Spring Mountain Road, Las Vegas, Nevada 89193. Telephone: 702-876-7237. Internet: www.swgas.com.

Shares of Southwest Gas have traded in a tight range over the past three months. The company reported a solid advance in revenues and share earnings for the March quarter. Strong growth in construction revenue more than offset lower gas operating revenue. Results at the utility business were supported by rate relief in Arizona, which became effective in January. The Arizona Corporation Commission allowed Southwest to increase revenues by $52.8 million, with a return on equity of 9.5%.

We look for a modest top-line advance and a healthy share-net gain for the current year. Measured growth will likely continue in 2013. The pipeline construction services subsidiary should continue to experience healthy demand. This line ought to further benefit from the replacement of aging infrastructure. Elsewhere, rate relief will boost the performance of the utility business, though it remains to be seen whether this unit's operating environment will continue to improve at the same pace. Customer growth is being boosted as vacant homes are reoccupied.

The company has filed a general rate case in Nevada. Southwest is requesting an increase in revenue of about $27 million, with a return on equity of 10.65%. It is asking that the new rates take effect in November of the current year. Efforts to procure rate relief should remain important, as the company depends on such approved increases to help it cope with rising expenses and to provide compensation for infrastructure investment.

The stock is not without risk. The company will probably incur greater operating costs as it continues to expand. Moreover, unfavorable temperature variations or lagging rate relief could hurt the performance of the utility business.

This issue has improved a notch in Timeliness since our March review, and now carries our Highest rank for year-ahead relative price performance. Looking further out, we anticipate steady growth in revenues, share earnings, and dividends for the company by 2015-2017. But from the recent quotation, appreciation potential is limited for the coming years. Moreover, this equity's dividend yield remains below average for a utility.

Michael Napoli, CFA *June 8, 2012*

(A) Based on avg. shares outstand. thru. '96, then diluted. Excl. nonrec. gains (losses): '97, 16¢; '02, (10¢); '05, (11¢); '06, 7¢. Next egs. report due in August. **(B)** Dividends historically paid early March, June, September, December. ■† Div'd reinvestment and stock purchase plan avail. **(C)** In millions.

Company's Financial Strength	B
Stock's Price Stability	95
Price Growth Persistence	65
Earnings Predictability	75

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Attachment F

Zacks.com Quotes and Research

AGL RESOURCES INC (NYSE)

ZACKS RANK: 3 - HOLD

GAS 38.75 ▲0.26 (0.68%) Vol. 649,483 16.00 CST

Current Quarter Estimate	0.30	Next Report Date	Aug 08, 2012
Next Quarter Estimate	0.21	EPS last quarter	1.16
Current Year Estimate	2.68	Last Quarter EPS Surprise	-12.12%
Next Year Estimate	2.99	EPS (Trailing 12 Mos.)	2.38
Expected Earnings Growth	4.28%	PE (forward)	14.35
Expected Sales Growth	-2.24%	ABR	2.57

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Premium Research: Stock Analysis

Zacks Rank ? Short-Term Rating 1-3 Months	PREMIUM
Zacks Recommendation ? Long-Term Rating 6+ Months	PREMIUM
Zacks Industry Rank ?	PREMIUM
Target Price ?	PREMIUM
Equity Research Report ? Updated as of 05/08/2012	PREMIUM

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Premium Research: Industry Analysis

Top Peers	Ticker	Zacks Rank
AGL RESOURCES INC	GAS	PREMIUM
CDN UTILITY A	T.CU	PREMIUM
VALENER INC	T.VNR	PREMIUM
VECTREN CORP	VVC	PREMIUM

See all UTIL-GAS DISTR Peers

Earnings Growth Estimates

	GAS	IND	S&P
Current Qtr (06/2012)	-9.7	N/A	N/A
Next Qtr (09/2012)	962.5	N/A	N/A
Current Year (06/2011)	-8.1	-1.0	6.8
Next Year (06/2012)	11.6	15.4	6.8
Past 5 Years	2.0	5.2	3.2
Next 5 Years	4.3	8.4	0.0
PE	16.2	14.1	13.0
PEG Ratio	3.4	1.8	0.0

Detailed Earnings Estimates

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Zacks Consensus Estimate	0.30	0.21	2.68	2.99
# of Estimates	5	4	7	8
Most Recent Estimate	0.32	0.12	2.70	2.72
High Estimate	0.39	0.32	2.90	3.05
Low Estimate	0.19	0.12	2.55	2.72
Year ago EPS	0.33	0.02	2.92	2.68
Year over Year Growth Est.	-9.70%	962.50%	-8.12%	11.63%

Agreement - Estimate Revisions

	Current Qtr (06/2012)	Next Qtr (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	0	0

Magnitude - Consensus Estimate Trend

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Current	0.30	0.21	2.68	2.99
7 Days Ago	0.30	0.21	2.68	2.99
30 Days Ago	0.30	0.21	2.68	2.99
60 Days Ago	0.31	0.16	2.84	3.04
90 Days Ago	0.31	0.16	2.85	3.08

Upside - Most Accurate Estimate versus Zacks Consensus

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Most Accurate Estimate	0.00	0.00	0.00	0.00
Zacks Consensus Estimate	0.30	0.21	2.68	2.99
Earnings ESP	0.00%	0.00%	0.00%	0.00%

Surprise - Reported Earnings History

	03/2012	12/2011	09/2011	06/2011	Average Surprise
Reported	1.16	0.87	0.02	0.33	
Estimate	1.32	0.92	0.00	0.28	
Difference	-0.16	-0.05	0.02	0.05	-0.04
Surprise	-12.12% ▼	-5.43% ▼	0.00% ▲	17.86% ▲	0.10% ▼

Earnings Transcript for GAS from 05/01/2012

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Zacks.com Quotes and Research

ATMOS ENERGY CORP (NYSE)

ZACKS RANK: 4 - SELL

ATO 35.07 ▲0.29 (0.83%) Vol. 1,025,678 16.00 CST

Current Quarter Estimate	0.16	Next Report Date	Aug 08, 2012
Next Quarter Estimate	0.17	EPS last quarter	1.28
Current Year Estimate	2.29	Last Quarter EPS Surprise	-10.49%
Next Year Estimate	2.48	EPS (Trailing 12 Mos.)	2.00
Expected Earnings Growth	4.78%	PE (forward)	15.18
Expected Sales Growth	-10.71%	ABR	2.57

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Premium Research: Stock Analysis

Zacks Rank ? Short-Term Rating 1-3 Months	PREMIUM
Zacks Recommendation ? Long-Term Rating 6+ Months	PREMIUM
Zacks Industry Rank ?	PREMIUM
Target Price ?	PREMIUM
Equity Research Report ? Updated as of 06/18/2012	PREMIUM

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Premium Research: Industry Analysis

Top Peers	Ticker	Zacks Rank
ATMOS ENERGY CORP	ATO	PREMIUM
CDN UTILITY A	T.CU	PREMIUM
VALENER INC	T.VNR	PREMIUM
VECTREN CORP	VVC	PREMIUM

See all UTIL-GAS DISTR Peers

Earnings Growth Estimates

	ATO	IND	S&P
Current Qtr (06/2012)	220.0	N/A	N/A
Next Qtr (09/2012)	179.2	N/A	N/A
Current Year (06/2011)	7.6	-1.0	6.8
Next Year (06/2012)	8.0	15.4	6.8
Past 5 Years	2.3	5.2	3.2
Next 5 Years	4.8	8.4	0.0
PE	17.4	14.1	13.0
PEG Ratio	3.2	1.8	0.0

Detailed Earnings Estimates

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (09/2012)	Next Year (09/2013)
Zacks Consensus Estimate	0.16	0.17	2.29	2.48
# of Estimates	5	4	8	8
Most Recent Estimate	0.17	0.22	2.28	2.55
High Estimate	0.22	0.22	2.35	2.55
Low Estimate	0.13	0.12	2.22	2.33
Year ago EPS	0.05	0.06	2.13	2.29
Year over Year Growth Est.	220.00%	179.17%	7.57%	8.02%

Agreement - Estimate Revisions

	Current Qtr (06/2012)	Next Qtr (09/2012)	Current Year (09/2012)	Next Year (09/2013)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	1	0

Magnitude - Consensus Estimate Trend

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (09/2012)	Next Year (09/2013)
Current	0.16	0.17	2.29	2.48
7 Days Ago	0.16	0.17	2.29	2.48
30 Days Ago	0.16	0.17	2.30	2.48
60 Days Ago	0.13	0.08	2.32	2.48
90 Days Ago	0.13	0.06	2.33	2.49

Upside - Most Accurate Estimate versus Zacks Consensus

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (09/2012)	Next Year (09/2013)
Most Accurate Estimate	0.00	0.00	2.35	0.00
Zacks Consensus Estimate	0.16	0.17	2.29	2.48
Earnings ESP	0.00%	0.00%	2.62% ▲	0.00%

Surprise - Reported Earnings History

	03/2012	12/2011	09/2011	06/2011	Average Surprise
Reported	1.28	0.61	0.06	0.05	
Estimate	1.43	0.85	0.04	0.08	
Difference	-0.15	-0.24	0.02	-0.03	-0.10
Surprise	-10.49%▼	-28.24%▼	50.00%▲	-37.50%▼	-6.56%▼

Earnings Transcript for ATO from 02/08/2012

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LACLEDE GROUP INC (NYSE)

ZACKS RANK: 3 - HOLD

LG 39.81 ▲0.60 (1.53%) Vol. 103,358 16.00 CST

Current Quarter Estimate	0.31	Next Report Date	Jul 27, 2012
Next Quarter Estimate	-0.20	EPS last quarter	1.27
Current Year Estimate	2.58	Last Quarter EPS Surprise	-7.3%
Next Year Estimate	2.68	EPS (Trailing 12 Mos.)	2.89
Expected Earnings Growth	3%	PE (forward)	15.21
Expected Sales Growth	-8.02%	ABR	3

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Premium Research: Stock Analysis

Zacks Rank ? upgraded 06/28/2012 Short-Term Rating 1-3 Months	PREMIUM
Zacks Recommendation ? Long-Term Rating 6+ Months	PREMIUM
Zacks Industry Rank ?	PREMIUM
Target Price ?	PREMIUM
Equity Research Report ? Updated as of 06/27/2012	PREMIUM

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Premium Research: Industry Analysis

Top Peers	Ticker	Zacks Rank
LACLEDE GROUP INC	LG	PREMIUM
CDN UTILITY A	T.CU	PREMIUM
VALENER INC	T.VNR	PREMIUM
VECTREN CORP	VVC	PREMIUM

See all UTIL-GAS DISTR Peers

Earnings Growth Estimates

	LG	IND	S&P
Current Qtr (06/2012)	-52.8	N/A	N/A
Next Qtr (09/2012)	-40.5	N/A	N/A
Current Year (06/2011)	-7.6	-1.0	6.8
Next Year (06/2012)	3.9	15.4	6.8
Past 5 Years	5.1	5.2	3.2
Next 5 Years	3.0	8.4	0.0
PE	13.6	14.1	13.0
PEG Ratio	5.1	1.8	0.0

Detailed Earnings Estimates

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (09/2012)	Next Year (09/2013)
Zacks Consensus Estimate	0.31	-0.20	2.58	2.68
# of Estimates	3	3	4	4
Most Recent Estimate	0.25	-0.27	2.59	2.65
High Estimate	0.35	-0.12	2.65	2.75
Low Estimate	0.25	-0.27	2.43	2.56
Year ago EPS	0.65	-0.14	2.79	2.58
Year over Year Growth Est.	-52.82%	-40.48%	-7.62%	3.88%

Agreement - Estimate Revisions

	Current Qtr (06/2012)	Next Qtr (09/2012)	Current Year (09/2012)	Next Year (09/2013)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	1	0	1	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	0	0

Magnitude - Consensus Estimate Trend

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (09/2012)	Next Year (09/2013)
Current	0.31	-0.20	2.58	2.68
7 Days Ago	0.31	-0.20	2.58	2.68
30 Days Ago	0.30	-0.20	2.58	2.68
60 Days Ago	0.33	-0.17	2.66	2.78
90 Days Ago	0.33	-0.16	2.68	2.79

Upside - Most Accurate Estimate versus Zacks Consensus

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (09/2012)	Next Year (09/2013)
Most Accurate Estimate	0.32	0.00	2.64	0.00
Zacks Consensus Estimate	0.31	-0.20	2.58	2.68
Earnings ESP	3.23% ▲	0.00%	2.33% ▲	0.00%

Surprise - Reported Earnings History

	03/2012	12/2011	09/2011	06/2011	Average Surprise
Reported	1.27	1.11	-0.14	0.65	
Estimate	1.37	1.14	-0.06	0.22	
Difference	-0.10	-0.03	-0.08	0.43	0.06
Surprise	-7.30% ▼	-2.63% ▼	-133.33% ▼	195.45% ▲	13.05% ▲

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NEW JERSEY RES (NYSE)

ZACKS RANK: 3 - HOLD

NJR 43.61 ▲0.61 (1.42%) Vol. 193,043 16.00 CST

Current Quarter Estimate	0.07	Next Report Date	Aug 08, 2012
Next Quarter Estimate	-0.16	EPS last quarter	1.79
Current Year Estimate	2.74	Last Quarter EPS Surprise	14.01%
Next Year Estimate	2.81	EPS (Trailing 12 Mos.)	3.13
Expected Earnings Growth	3.8%	PE (forward)	15.69
Expected Sales Growth	-4.64%	ABR	3.33

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Premium Research: Stock Analysis

Zacks Rank ? downgraded 06/22/2012 Short-Term Rating 1-3 Months	PREMIUM
Zacks Recommendation ? Long-Term Rating 6+ Months	PREMIUM
Zacks Industry Rank ?	PREMIUM
Target Price ?	PREMIUM
Equity Research Report ? Updated as of 06/21/2012	PREMIUM

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Premium Research: Industry Analysis

Top Peers	Ticker	Zacks Rank
NEW JERSEY RES	NJR	PREMIUM
CDN UTILITY A	T.CU	PREMIUM
VALENER INC	T.VNR	PREMIUM
VECTREN CORP	VVC	PREMIUM

See all UTIL-GAS DISTR Peers

Earnings Growth Estimates

	NJR	IND	S&P
Current Qtr (06/2012)	-69.6	N/A	N/A
Next Qtr (09/2012)	-912.5	N/A	N/A
Current Year (06/2011)	7.1	-1.0	6.8
Next Year (06/2012)	2.6	15.4	6.8
Past 5 Years	8.1	5.2	3.2
Next 5 Years	3.8	8.4	0.0
PE	13.7	14.1	13.0
PEG Ratio	4.1	1.8	0.0

Detailed Earnings Estimates

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (09/2012)	Next Year (09/2013)
Zacks Consensus Estimate	0.07	-0.16	2.74	2.81
# of Estimates	5	4	7	7
Most Recent Estimate	0.05	-0.13	2.80	2.80
High Estimate	0.13	-0.13	2.80	2.95
Low Estimate	0.02	-0.24	2.70	2.61
Year ago EPS	0.23	0.02	2.56	2.74
Year over Year Growth Est.	-69.57%	-912.50%	7.09%	2.61%

Agreement - Estimate Revisions

	Current Qtr (06/2012)	Next Qtr (09/2012)	Current Year (09/2012)	Next Year (09/2013)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	1	1	1	1

Magnitude - Consensus Estimate Trend

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (09/2012)	Next Year (09/2013)
Current	0.07	-0.16	2.74	2.81
7 Days Ago	0.07	-0.16	2.74	2.81
30 Days Ago	0.07	-0.14	2.76	2.82
60 Days Ago	0.18	-0.07	2.74	2.82
90 Days Ago	0.18	-0.06	2.77	2.89

Upside - Most Accurate Estimate versus Zacks Consensus

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (09/2012)	Next Year (09/2013)
Most Accurate Estimate	0.09	-0.13	2.78	2.80
Zacks Consensus Estimate	0.07	-0.16	2.74	2.81
Earnings ESP	28.57% ▲	18.75% ▲	1.46% ▲	-0.36% ▼

Surprise - Reported Earnings History

	03/2012	12/2011	09/2011	06/2011	Average Surprise
Reported	1.79	1.09	0.02	0.23	
Estimate	1.57	0.74	0.04	0.22	
Difference	0.22	0.35	-0.02	0.01	0.14
Surprise	14.01%▲	47.30%▲	-50.00%▼	4.55%▲	3.97%▲

Earnings Transcript for NJR from 02/03/2010

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NORTHWEST NAT GAS CO (NYSE)

ZACKS RANK: 3 - HOLD

NWN 47.60 -0.22 (-0.46%) Vol. 233,489 16.00 CST

Current Quarter Estimate	0.16	Next Report Date	Aug 08, 2012
Next Quarter Estimate	-0.31	EPS last quarter	1.51
Current Year Estimate	2.50	Last Quarter EPS Surprise	0%
Next Year Estimate	2.68	EPS (Trailing 12 Mos.)	2.54
Expected Earnings Growth	4.3%	PE (forward)	19.14
Expected Sales Growth	-5.84%	ABR	2.33

Learn More About Estimate Research
See Brokerage Recommendations

Premium Research: Stock Analysis

Zacks Rank ? Short-Term Rating 1-3 Months	PREMIUM
Zacks Recommendation ? Long-Term Rating 6+ Months	PREMIUM
Zacks Industry Rank ?	PREMIUM
Target Price ?	PREMIUM
Equity Research Report ? Updated as of 06/22/2012	PREMIUM

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Top Peers	Ticker	Zacks Rank
NORTHWEST NAT GAS CO	NWN	PREMIUM
CDN UTILITY A	T.CU	PREMIUM
VALENER INC	T.VNR	PREMIUM
VECTREN CORP	VVC	PREMIUM

See all UTIL-GAS DISTR Peers

Earnings Growth Estimates

	NWN	IND	S&P
Current Qtr (06/2012)	-35.2	N/A	N/A
Next Qtr (09/2012)	-1.3	N/A	N/A
Current Year (06/2011)	-2.0	-1.0	6.8
Next Year (06/2012)	7.3	15.4	6.8
Past 5 Years	1.3	5.2	3.2
Next 5 Years	4.3	8.4	0.0
PE	18.8	14.1	13.0
PEG Ratio	4.5	1.8	0.0

Detailed Earnings Estimates

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Zacks Consensus Estimate	0.16	-0.31	2.50	2.68
# of Estimates	5	5	7	7
Most Recent Estimate	0.22	-0.35	2.45	2.55
High Estimate	0.22	-0.30	2.55	2.80
Low Estimate	0.11	-0.35	2.45	2.55
Year ago EPS	0.25	-0.31	2.55	2.50
Year over Year Growth Est.	-35.20%	-1.29%	-2.02%	7.26%

Agreement - Estimate Revisions

	Current Qtr (06/2012)	Next Qtr (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	0	0

Magnitude - Consensus Estimate Trend

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Current	0.16	-0.31	2.50	2.68
7 Days Ago	0.16	-0.31	2.50	2.68
30 Days Ago	0.16	-0.31	2.50	2.68
60 Days Ago	0.14	-0.31	2.51	2.69
90 Days Ago	0.14	-0.31	2.50	2.70

Upside - Most Accurate Estimate versus Zacks Consensus

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Most Accurate Estimate	0.00	0.00	0.00	0.00
Zacks Consensus Estimate	0.16	-0.31	2.50	2.68
Earnings ESP	0.00%	0.00%	0.00%	0.00%

Surprise - Reported Earnings History

	03/2012	12/2011	09/2011	06/2011	Average Surprise
Reported	1.51	1.09	-0.31	0.25	
Estimate	1.51	1.05	-0.33	0.23	
Difference	0.00	0.04	0.02	0.02	0.03
Surprise	0.00%	3.81%	6.06%	8.70%	6.19%

Earnings Transcript for NWN from 11/06/2010

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PIEDMONT NAT GAS INC (NYSE)

ZACKS RANK: 3 - HOLD

PNY 32.19 -0.33 (-1.01%) Vol. 403,998 16.00 CST

Current Quarter Estimate	-0.08	Next Report Date	Sep 07, 2012
Next Quarter Estimate	-0.08	EPS last quarter	0.70
Current Year Estimate	1.59	Last Quarter EPS Surprise	-2.78%
Next Year Estimate	1.76	EPS (Trailing 12 Mos.)	1.50
Expected Earnings Growth	4.78%	PE (forward)	20.51
Expected Sales Growth	-8.62%	ABR	3.29

Learn More About Estimate Research
See Brokerage Recommendations

Premium Research: Stock Analysis

Zacks Rank ? upgraded 06/12/2012 Short-Term Rating 1-3 Months	PREMIUM
Zacks Recommendation ? Long-Term Rating 6+ Months	PREMIUM
Zacks Industry Rank ?	PREMIUM
Target Price ?	PREMIUM
Equity Research Report ? Updated as of 06/26/2012	PREMIUM

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Premium Research: Industry Analysis

Top Peers	Ticker	Zacks Rank
PIEDMONT NAT GAS INC	PNY	PREMIUM
CDN UTILITY A	T.CU	PREMIUM
VALENER INC	T.VNR	PREMIUM
VECTREN CORP	VVC	PREMIUM

See all UTIL-GAS DISTR Peers

Earnings Growth Estimates

	PNY	IND	S&P
Current Qtr (07/2012)	30.6	N/A	N/A
Next Qtr (10/2012)	38.5	N/A	N/A
Current Year (06/2011)	1.0	-1.0	6.8
Next Year (06/2012)	11.2	15.4	6.8
Past 5 Years	3.2	5.2	3.2
Next 5 Years	4.8	8.4	0.0
PE	21.7	14.1	13.0
PEG Ratio	4.3	1.8	0.0

Detailed Earnings Estimates

	Current Quarter (07/2012)	Next Quarter (10/2012)	Current Year (10/2012)	Next Year (10/2013)
Zacks Consensus Estimate	-0.08	-0.08	1.59	1.76
# of Estimates	6	5	7	7
Most Recent Estimate	-0.08	-0.07	1.60	1.79
High Estimate	-0.07	-0.07	1.60	1.80
Low Estimate	-0.10	-0.10	1.57	1.70
Year ago EPS	-0.12	-0.13	1.57	1.59
Year over Year Growth Est.	30.56%	38.46%	1.00%	11.17%

Agreement - Estimate Revisions

	Current Qtr (07/2012)	Next Qtr (10/2012)	Current Year (10/2012)	Next Year (10/2013)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	2	2	2	2
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	2	2

Magnitude - Consensus Estimate Trend

	Current Quarter (07/2012)	Next Quarter (10/2012)	Current Year (10/2012)	Next Year (10/2013)
Current	-0.08	-0.08	1.59	1.76
7 Days Ago	-0.08	-0.08	1.59	1.76
30 Days Ago	-0.11	-0.09	1.58	1.75
60 Days Ago	-0.11	-0.09	1.59	1.75
90 Days Ago	-0.11	-0.09	1.59	1.75

Upside - Most Accurate Estimate versus Zacks Consensus

	Current Quarter (07/2012)	Next Quarter (10/2012)	Current Year (10/2012)	Next Year (10/2013)
Most Accurate Estimate	-0.08	-0.08	1.59	1.75
Zacks Consensus Estimate	-0.08	-0.08	1.59	1.76
Earnings ESP	0.00%	0.00%	0.00%	-0.57% ▼

Surprise - Reported Earnings History

	04/2012	01/2012	10/2011	07/2011	Average Surprise
Reported	0.70	1.05	-0.13	-0.12	
Estimate	0.72	1.19	-0.13	-0.11	
Difference	-0.02	-0.14	0.00	-0.01	-0.06
Surprise	-2.78% ▼	-11.76% ▼	0.00% ▲	-9.09% ▼	-7.88% ▼

Earnings Transcript for PNY from 01/05/2010

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SOUTH JERSEY INDS INC (NYSE)

ZACKS RANK: 3 - HOLD

SJI 50.97 -0.01 (-0.02%) Vol. 167,372 16.00 CST

Current Quarter Estimate	0.28	Next Report Date	Aug 06, 2012
Next Quarter Estimate	0.05	EPS last quarter	1.65
Current Year Estimate	3.07	Last Quarter EPS Surprise	-1.79%
Next Year Estimate	3.38	EPS (Trailing 12 Mos.)	2.91
Expected Earnings Growth	6%	PE (forward)	16.61
Expected Sales Growth	-2.52%	ABR	1.5

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See Brokerage Recommendations

Premium Research: Stock Analysis

Zacks Rank ? Short-Term Rating 1-3 Months	PREMIUM
Zacks Recommendation ? Long-Term Rating 6+ Months	PREMIUM
Zacks Industry Rank ?	PREMIUM
Target Price ?	PREMIUM
Equity Research Report ? Updated as of 06/27/2012	PREMIUM

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Premium Research: Industry Analysis

Top Peers	Ticker	Zacks Rank
SOUTH JERSEY INDS INC	SJI	PREMIUM
CDN UTILITY A	T.CU	PREMIUM
VALENER INC	T.VNR	PREMIUM
VECTREN CORP	VVC	PREMIUM

See all UTIL-GAS DISTR Peers

Earnings Growth Estimates

	SJI	IND	S&P
Current Qtr (06/2012)	37.5	N/A	N/A
Next Qtr (09/2012)	450.0	N/A	N/A
Current Year (06/2011)	6.2	-1.0	6.8
Next Year (06/2012)	10.1	15.4	6.8
Past 5 Years	6.7	5.2	3.2
Next 5 Years	6.0	8.4	0.0
PE	17.5	14.1	13.0
PEG Ratio	2.8	1.8	0.0

Detailed Earnings Estimates

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Zacks Consensus Estimate	0.28	0.05	3.07	3.38
# of Estimates	2	2	2	4
Most Recent Estimate	0.26	0.08	3.03	3.27
High Estimate	0.29	0.08	3.11	3.45
Low Estimate	0.26	0.03	3.03	3.27
Year ago EPS	0.20	0.01	2.89	3.07
Year over Year Growth Est.	37.50%	450.00%	6.23%	10.10%

Agreement - Estimate Revisions

	Current Qtr (06/2012)	Next Qtr (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	0	0

Magnitude - Consensus Estimate Trend

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Current	0.28	0.05	3.07	3.38
7 Days Ago	0.28	0.05	3.07	3.38
30 Days Ago	0.28	0.05	3.07	3.38
60 Days Ago	0.28	0.07	3.13	3.36
90 Days Ago	0.27	0.08	3.14	3.34

Upside - Most Accurate Estimate versus Zacks Consensus

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Most Accurate Estimate	0.00	0.00	0.00	0.00
Zacks Consensus Estimate	0.28	0.05	3.07	3.38
Earnings ESP	0.00%	0.00%	0.00%	0.00%

Surprise - Reported Earnings History

	03/2012	12/2011	09/2011	06/2011	Average Surprise
Reported	1.65	1.05	0.01	0.20	
Estimate	1.68	1.04	0.06	0.28	
Difference	-0.03	0.01	-0.05	-0.08	-0.04
Surprise	-1.79% ▼	0.96% ▲	-83.33% ▼	-28.57% ▼	-28.18% ▼

Earnings Transcript for SJI from 05/10/2010

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SOUTHWEST GAS CORP (NYSE)

ZACKS RANK: 3 - HOLD

SWX 43.65 ▲0.05 (0.11%) Vol. 388,718 16.00 CST

Current Quarter Estimate	0.09	Next Report Date	Aug 06, 2012
Next Quarter Estimate	-0.25	EPS last quarter	1.70
Current Year Estimate	2.70	Last Quarter EPS Surprise	7.59%
Next Year Estimate	2.86	EPS (Trailing 12 Mos.)	2.72
Expected Earnings Growth	4.43%	PE (forward)	16.16
Expected Sales Growth	-4.3%	ABR	2.57

Learn More About Estimate Research
See Brokerage Recommendations

Premium Research: Stock Analysis

Zacks Rank ? Short-Term Rating 1-3 Months	PREMIUM
Zacks Recommendation ? Long-Term Rating 6+ Months	PREMIUM
Zacks Industry Rank ?	PREMIUM
Target Price ?	PREMIUM
Equity Research Report ? Updated as of 06/20/2012	PREMIUM

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Top Peers	Ticker	Zacks Rank
SOUTHWEST GAS CORP	SWX	PREMIUM
CDN UTILITY A	T.CU	PREMIUM
VALENER INC	T.VNR	PREMIUM
VECTREN CORP	VVC	PREMIUM

See all UTIL-GAS DISTR Peers

Earnings Growth Estimates

	SWX	IND	S&P
Current Qtr (06/2012)	211.1	N/A	N/A
Next Qtr (09/2012)	-23.3	N/A	N/A
Current Year (06/2011)	14.3	-1.0	6.8
Next Year (06/2012)	5.9	15.4	6.8
Past 5 Years	6.2	5.2	3.2
Next 5 Years	4.4	8.4	0.0
PE	16.0	14.1	13.0
PEG Ratio	3.6	1.8	0.0

Detailed Earnings Estimates

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Zacks Consensus Estimate	0.09	-0.25	2.70	2.86
# of Estimates	3	3	6	7
Most Recent Estimate	0.09	-0.18	2.70	2.92
High Estimate	0.15	-0.18	2.77	2.98
Low Estimate	0.04	-0.30	2.60	2.75
Year ago EPS	0.03	-0.20	2.36	2.70
Year over Year Growth Est.	211.11%	-23.33%	14.34%	5.89%

Agreement - Estimate Revisions

	Current Qtr (06/2012)	Next Qtr (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	0	0

Magnitude - Consensus Estimate Trend

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Current	0.09	-0.25	2.70	2.86
7 Days Ago	0.09	-0.25	2.70	2.86
30 Days Ago	0.09	-0.25	2.70	2.86
60 Days Ago	0.11	-0.24	2.67	2.84
90 Days Ago	0.09	-0.23	2.60	2.74

Upside - Most Accurate Estimate versus Zacks Consensus

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Most Accurate Estimate	0.00	0.00	0.00	0.00
Zacks Consensus Estimate	0.09	-0.25	2.70	2.86
Earnings ESP	0.00%	0.00%	0.00%	0.00%

Surprise - Reported Earnings History

	03/2012	12/2011	09/2011	06/2011	Average Surprise
Reported	1.70	1.19	-0.20	0.03	
Estimate	1.58	0.99	-0.20	0.04	
Difference	0.12	0.20	0.00	-0.01	0.10
Surprise	7.59% ▲	20.20% ▲	0.00% ▲	-25.00% ▼	0.93% ▲

Earnings Transcript for SWX from 03/02/2010

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Response No. MCC-092
Attachment G

Go to...

Section 1: 10-Q (FORM 10-Q)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

☑ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Quarterly Period Ended March 31, 2012

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File Number 1-14174

AGL RESOURCES INC.

(Exact name of registrant as specified in its charter)

Georgia	**58-2210952**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

Ten Peachtree Place NE, Atlanta, Georgia 30309
(Address and zip code of principal executive offices)

404-584-4000
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☑ Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2). Yes ☐ No ☑

Indicate the number of shares outstanding of each of the issuer's classes of common stock as of the latest practicable date.

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PART 1 - Financial Information
Item 1. Financial Statements

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION
(UNAUDITED)

In millions	March 31, 2012	As of December 31, 2011	March 31, 2011
Current assets			
Cash and cash equivalents	$ 71	$ 69	$ 85
Short-term investments	57	53	0
Receivables			
Energy marketing receivables	386	607	565
Gas, unbilled and other receivables	577	692	367
Less allowance for uncollectible accounts	19	15	21
Total receivables	944	1,284	911
Inventories, net	464	750	361
Derivative instruments – current portion	218	226	111
Regulatory assets – current portion	137	131	73
Other current assets	131	233	46
Total current assets	2,022	2,746	1,587
Long-term assets and other deferred debits			
Property, plant and equipment	9,920	9,779	6,348
Less accumulated depreciation	1,947	1,879	1,830
Property, plant and equipment, net	7,973	7,900	4,518
Goodwill	1,813	1,813	418
Regulatory assets – noncurrent portion	1,057	1,079	434
Derivative instruments – noncurrent portion	48	62	29
Other	326	313	40
Total long-term assets and other deferred debits	11,217	11,167	5,439
Total assets	$ 13,239	$ 13,913	$ 7,026
Current liabilities			
Energy marketing trade payables	$ 425	$ 590	$ 628
Accounts payable – trade	205	294	154
Regulatory liabilities – current portion	173	112	77
Accrued expenses	145	162	141
Accrued regulatory infrastructure program costs – current portion	149	131	69
Short-term debt	730	1,321	25
Derivative instruments – current portion	93	99	25
Accrued environmental remediation liabilities – current portion	39	37	15
Other current liabilities	389	338	179
Total current liabilities	2,348	3,084	1,313
Long-term liabilities and other deferred credits			
Long-term debt	3,558	3,561	2,173
Accumulated deferred income taxes	1,447	1,445	803
Regulatory liabilities – noncurrent portion	1,431	1,405	296
Accrued pension obligations	228	238	153
Accrued regulatory infrastructure program costs	110	145	143
Accrued environmental remediation liabilities	289	290	126
Accrued other retirement benefit costs	318	320	34
Derivative instruments – noncurrent portion	10	11	3
Other long-term liabilities and other deferred credits	74	75	62
Total long-term liabilities and other deferred credits	7,465	7,490	3,793
Total liabilities and other deferred credits	9,813	10,574	5,106
Commitments, guarantees and contingencies (see Note 9)			

Equity			
AGL Resources Inc. common shareholders' equity, $5 par value; 750,000,000 shares authorized	3,410	3,318	1,903
Noncontrolling interest	16	21	17
Total equity	3,426	3,339	1,920
Total liabilities and equity	$ 13,239	$ 13,913	$ 7,026

See Notes to Condensed Consolidated Financial Statements (Unaudited).

Glossary of Key Terms

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Note 7 - Debt

The following table provides maturity dates, year-to-date weighted average interest rates and amounts outstanding for our various debt securities and facilities that are included in our unaudited Condensed Consolidated Statements of Financial Position. For additional information on our debt see Note 7 in our Consolidated Financial Statements and related notes in Item 8 of our 2011 Form 10-K.

		March 31, 2012			March 31, 2011	
Dollars in millions	Year(s) due	Weighted average interest rate (1)	Outstandin	Outstanding at December 31, 2011	Weighted average interest rate (1)	Outstandin
Short-term debt						
Commercial paper- AGL Capital	2012	0.5%	$ 625	$ 869	0.4%	$ 25
Commercial paper- Nicor Gas	2012	0.5	105	452	n/a	n/a
Current portion of long-term debt	2012	8.3	15	15	n/a	0
Current portion of capital leases	2012	4.9	2	2	4.9	1
Total short-term debt and current portion of long-term debt and capital leases		**0.6%**	**$ 747**	**$ 1,338**	**0.4%**	**$ 26**
Long-term debt – excluding current portion						
Senior notes	2013-2041	5.1%	$ 2,550	$ 2,550	5.5%	$ 1,775
First mortgage bonds	2016-2038	5.6	500	500	n/a	n/a
Gas facility revenue bonds	2022-2033	1.1	200	200	1.2	200
Medium-term notes	2017-2027	7.8	181	181	7.8	196
Capital leases	2012	n/a	0	0	4.9	2
Total principal long-term debt		4.9%	$ 3,431	$ 3,431	5.3%	$ 2,173
First mortgage bonds fair value adjustment	2016-2038	n/a	$ 97	$ 99	n/a	n/a
Interest rate swaps fair value adjustment	2016	n/a	12	13	n/a	0
Unamortized debt premium (discount), net	-	n/a	18	18	n/a	n/a
Total non-principal long-term debt		n/a	$ 127	$ 130	n/a	$ 0
Total long-term debt			**$ 3,558**	**$ 3,561**		**$ 2,173**
Total debt			**$ 4,305**	**$ 4,899**		**$ 2,199**

(1) Interest rates are calculated based on the daily average balance outstanding.

Financial and Non-Financial Covenants

The AGL Credit Facility and the Nicor Gas Credit Facility each include a financial covenant that requires us to maintain a ratio of total debt to total capitalization of no more than 70%; however, our goal is to maintain this ratio at levels between 50% and 60%. These ratios, as calculated in accordance with the debt covenants include standby letters of credit and surety bonds and exclude OCI pension adjustments. Adjusting for these items, the following table contains our debt-to-capitalization ratios for the periods presented.

	March 31, 2012	December 31, 2011	March 31, 2011

AGL Credit Facility	54%	58%	51%
Nicor Gas Credit Facility	47%	60%	n/a

The credit facilities contain certain non-financial covenants that, among other things, restrict liens and encumbrances, loans and investments, acquisitions, dividends and other restricted payments, asset dispositions, mergers and consolidations and other matters customarily restricted in such agreements.

Default Provisions

Our credit facilities and other financial obligations include provisions that, if not complied with, could require early payment or similar actions. The most important default events include:

- a maximum leverage ratio
- insolvency events and nonpayment of scheduled principal or interest payments
- acceleration of other financial obligations
- change of control provisions

Glossary of Key Terms

Go to...

Section 1: 10-Q (FORM 10-Q)

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

(Mark One)

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2012

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number 1-10042

Atmos Energy Corporation

(Exact name of registrant as specified in its charter)

Texas and Virginia *(State or other jurisdiction of incorporation or organization)*	**75-1743247** *(IRS employer identification no.)*
Three Lincoln Centre, Suite 1800 **5430 LBJ Freeway, Dallas, Texas** *(Address of principal executive offices)*	**75240** *(Zip code)*

(972) 934-9227
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer ☑ Accelerated Filer ☐ Non-Accelerated Filer ☐ Smaller Reporting Company ☐
(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act) Yes ☐ No ☑

Number of shares outstanding of each of the issuer's classes of common stock, as of April 27, 2012.

Class	Shares Outstanding
No Par Value	90,030,471

PART I. FINANCIAL INFORMATION

Item 1. ***Financial Statements***

ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

	March 31, 2012 (Unaudited)	September 30, 2011
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$6,992,899	$6,816,794
Less accumulated depreciation and amortization	1,658,887	1,668,876
Net property, plant and equipment	5,334,012	5,147,918
Current assets		
Cash and cash equivalents	47,040	131,419
Accounts receivable, net	350,261	273,303
Gas stored underground	221,112	289,760
Other current assets	275,428	316,471
Total current assets	893,841	1,010,953
Goodwill and intangible assets	740,185	740,207
Deferred charges and other assets	400,689	383,793
	$7,368,727	$7,282,871
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: March 31, 2012 — 90,029,852 shares; September 30, 2011 — 90,296,482 shares	$ 450	$ 451
Additional paid-in capital	1,728,150	1,732,935
Retained earnings	685,206	570,495
Accumulated other comprehensive loss	(53,094)	(48,460)
Shareholders' equity	2,360,712	2,255,421
Long-term debt	1,956,213	2,206,117
Total capitalization	4,316,925	4,461,538
Current liabilities		
Accounts payable and accrued liabilities	309,864	291,205
Other current liabilities	374,123	367,563
Short-term debt	173,996	206,396
Current maturities of long-term debt	250,131	2,434
Total current liabilities	1,108,114	867,598
Deferred income taxes	1,062,488	960,093
Regulatory cost of removal obligation	414,001	428,947
Deferred credits and other liabilities	467,199	564,695
	$7,368,727	$7,282,871

See accompanying notes to condensed consolidated financial statements.

Go to...

Section 1: 10-Q (THE LACLEDE GROUP, INC FORM 10-Q MAR 2012)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549

FORM 10-Q

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 or 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934 **For the Quarter Ended March 31, 2012**

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 or 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934 For the Transition Period from _____ to _____

Commission File Number 1-16681

THE LACLEDE GROUP, INC.
(Exact name of registrant as specified in its charter)

Missouri	**74-2976504**
(State of Incorporation)	(I.R.S. Employer Identification number)

720 Olive Street
St. Louis, MO 63101
(Address and zip code of principal executive offices)

314-342-0500
(Registrant's telephone number, including area code)

Indicate by check mark if the registrant:

(1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such report) and (2) has been subject to such filing requirements for the past 90 days. Yes [X] No [ ]

has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes [X] No [ ]

is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer [X] Accelerated filer [ ]

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THE LACLEDE GROUP, INC.
CONSOLIDATED BALANCE SHEETS (Continued)
(UNAUDITED)

(Thousands, except share amounts)	March 31, 2012	Sept. 30, 2011	March 31, 2011
CAPITALIZATION AND LIABILITIES			
Capitalization:			
Common stock (70,000,000 shares authorized, 22,489,986, 22,430,734, and 22,400,309 shares issued, respectively)	$ 22,490	$ 22,431	$ 22,400
Paid-in capital	165,056	163,702	160,152
Retained earnings	425,500	389,298	394,887
Accumulated other comprehensive income (loss)	2,158	(2,100)	(8,272)
Total Common Stock Equity	615,204	573,331	569,167
Long-term debt (less current portion) – Laclede Gas	339,386	364,357	364,327
Total Capitalization	954,590	937,688	933,494
Current Liabilities:			
Notes payable	—	46,000	—
Accounts payable	73,045	96,561	96,808
Advance customer billings	—	15,230	—
Current portion of long-term debt	25,000	—	—
Wages and compensation accrued	13,873	13,650	13,504
Dividends payable	9,697	9,359	9,244
Customer deposits	9,459	10,048	10,719
Interest accrued	8,789	8,812	9,023
Taxes accrued	25,062	11,901	36,509
Deferred income taxes	6,615	8,405	—
Other	16,220	11,968	13,307
Total Current Liabilities	187,760	231,934	189,114
Deferred Credits and Other Liabilities:			
Deferred income taxes	335,215	315,405	293,466
Unamortized investment tax credits	3,219	3,326	3,432
Pension and postretirement benefit costs	163,940	185,701	208,727
Asset retirement obligations	28,313	27,495	26,610
Regulatory liabilities	53,267	50,846	49,077
Other	31,827	30,687	30,497
Total Deferred Credits and Other Liabilities	615,781	613,460	611,809
Commitments and Contingencies (Note 11)			
Total Capitalization and Liabilities	$ 1,758,131	$ 1,783,082	$ 1,734,417

See Notes to Consolidated Financial Statements.

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Laclede Group has a registration statement on file on Form S-3 for the issuance and sale of up to 285,222 shares of its common stock under its Dividend Reinvestment and Stock Purchase Program. There were 262,856 and 254,164 shares at March 31, 2012 and April 27, 2012, respectively, remaining available for issuance under its Form S-3. Laclede Group also has an automatic shelf registration statement on Form S-3 for the issuance of equity and debt securities. No securities have been issued under that S-3. The amount, timing, and type of financing to be issued under this shelf registration will depend on cash requirements and market conditions.

Guarantees

Laclede Group had guarantees totaling $86.3 million for performance and payment of certain wholesale gas supply purchases by LER, as of March 31, 2012. Since that date, total guarantees issued by Laclede Group on behalf of LER decreased by $2.0 million, bringing the total to $84.3 million in guarantees outstanding at April 27, 2012. No amounts have been recorded for these guarantees in the financial statements.

Other

The Company's and the Utility's access to capital markets, including the commercial paper market, and their respective financing costs, may depend on the credit rating of the entity that is accessing the capital markets. The credit ratings of the Company and the Utility remain at investment grade, but are subject to review and change by the rating agencies.

Utility capital expenditures were $40.5 million for the six months ended March 31, 2012, compared with $29.6 million for the same period last year. The increase in capital expenditures, compared with the prior period, is primarily attributable to additional expenditures for distribution plant and information technology investments. During fiscal 2011, Laclede Gas began a multi-year project to enhance its technology, customer service, and business processes by replacing its existing work management, financial, and supply chain software applications. Non-utility capital expenditures were $0.1 million for six months ended March 31, 2012 and 2011.

Consolidated capitalization at March 31, 2012 consisted of 64.4% Laclede Group common stock equity and 35.6% Laclede Gas long-term debt.

It is management's view that the Company has adequate access to capital markets and will have sufficient capital resources, both internal and external, to meet anticipated capital requirements, which primarily include capital expenditures, scheduled maturities of long-term debt, short-term seasonal needs, and dividends.

The seasonal nature of Laclede Gas' sales affects the comparison of certain balance sheet items at March 31, 2012 and at September 30, 2011, such as Accounts receivable - net, Gas stored underground, Notes payable, Accounts payable, Regulatory assets and Regulatory liabilities, and Advance and Delayed customer billings. The Consolidated Balance Sheet at March 31, 2011 is presented to facilitate comparison of these items with the corresponding interim period of the preceding fiscal year.

CONTRACTUAL OBLIGATIONS

As of March 31, 2012, Laclede Group had contractual obligations with payments due as summarized below (in millions):

		Payments due by period			
Contractual Obligations	Total	Remaining Fiscal Year 2012	Fiscal Years 2013-2014	Fiscal Years 2015-2016	Fiscal Years 2017 and thereafter
Principal Payments on Long-Term Debt	$ 365.0	$ —	$ 25.0	$ —	$ 340.0
Interest Payments on Long-Term Debt	449.6	11.4	43.5	42.7	352.0
Capital Leases (a)	0.3	0.1	0.1	0.1	—
Operating Leases (a)	9.2	2.1	6.3	0.8	—
Purchase Obligations – Natural Gas (b)	393.9	197.7	173.5	15.3	7.4
Purchase Obligations – Other (c)	88.3	24.7	23.4	18.4	21.8
Total (d)	$ 1,306.3	$ 236.0	$ 271.8	$ 77.3	$ 721.2

Go to...

Section 1: 10-Q

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10−Q

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2012

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE TRANSITION PERIOD FROM TO

Commission file number 1−8359

NEW JERSEY RESOURCES CORPORATION

(Exact name of registrant as specified in its charter)

New Jersey	**22−2376465**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
1415 Wyckoff Road, Wall, New Jersey 07719	**732−938−1480**
(Address of principal executive offices)	(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12 (b) of the Act:

Common Stock − $2.50 Par Value	**New York Stock Exchange**
(Title of each class)	(Name of each exchange on which registered)

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes: ☒ **No:** ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes: ☒ **No:** ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a

New Jersey Resources Corporation
Part I

ITEM 1. FINANCIAL STATEMENTS
(Continued)

CAPITALIZATION AND LIABILITIES

(Thousands)	**March 31, 2012**	September 30, 2011
CAPITALIZATION		
Common stock equity	**$ 862,242**	$ 776,257
Long-term debt	**429,450**	426,797
Total capitalization	**1,291,692**	1,203,054
CURRENT LIABILITIES		
Current maturities of long-term debt	**8,117**	7,575
Short-term debt	**191,300**	159,350
Gas purchases payable	**171,750**	252,691
Accounts payable and other	**63,268**	65,960
Dividends payable	**15,780**	14,912
Deferred and accrued taxes	**17,295**	778
Regulatory liabilities	**—**	4,633
New Jersey clean energy program	**13,522**	15,011
Derivatives, at fair value	**92,028**	68,698
Restricted broker margin accounts	**29,671**	—
Customers' credit balances and deposits	**31,455**	113,776
Total current liabilities	**634,186**	703,384
NONCURRENT LIABILITIES		
Deferred income taxes	**353,237**	327,782
Deferred investment tax credits	**6,066**	6,227
Deferred revenue	**5,966**	7,633
Derivatives, at fair value	**3,751**	6,341
Manufactured gas plant remediation	**182,900**	182,900
Postemployment employee benefit liability	**95,176**	114,305
Regulatory liabilities	**63,391**	59,837
New Jersey clean energy program	**—**	5,133
Asset retirement obligation	**27,537**	27,026
Other	**5,837**	5,822
Total noncurrent liabilities	**743,861**	743,006
Commitments and contingent liabilities (Note 11)		
Total capitalization and liabilities	**$ 2,669,739**	$ 2,649,444

See Notes to Unaudited Condensed Consolidated Financial Statements

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2012

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Transition period from _____ to _____

Commission File No. 1-15973

NORTHWEST NATURAL GAS COMPANY
(Exact name of registrant as specified in its charter)

Oregon (State or other jurisdiction of incorporation or organization)	**93-0256722** (I.R.S. Employer Identification No.)

220 N.W. Second Avenue, Portland, Oregon 97209
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: **(503) 226-4211**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [X] No [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes [X] No [ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer [X]	Accelerated filer [ ]
Non-accelerated filer [ ]	Smaller reporting company [ ] (Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes [ ] No [X]

At April 30, 2012, 26,800,474 shares of the registrant's Common Stock (the only class of Common Stock) were outstanding.

Consolidated Balance Sheets
(Unaudited)

Thousands	March 31, 2012	March 31, 2011	December 31, 2011
Capitalization and liabilities:			
Capitalization:			
Common stock - no par value; authorized 100,000 shares; issued and outstanding 26,798, 26,673, and 26,756 at March 31, 2012 and 2011 and December 31, 2011, respectively	$ 351,005	$ 343,787	$ 348,383
Retained earnings	402,599	385,899	373,905
Accumulated other comprehensive income (loss)	(7,633)	(6,458)	(7,800)
Total common stock equity	745,971	723,228	714,488
Long-term debt	641,700	551,700	641,700
Total capitalization	1,387,671	1,274,928	1,356,188
Current liabilities:			
Short-term debt	113,700	186,435	141,600
Current maturities of long-term debt	-	50,000	40,000
Accounts payable	60,165	71,839	86,300
Taxes accrued	10,509	10,063	10,747
Interest accrued	10,648	11,470	5,857
Regulatory liabilities	50,341	29,016	31,046
Derivative instruments	53,697	25,655	57,317
Other current liabilities	41,503	38,433	41,597
Total current liabilities	340,563	422,911	414,464
Deferred credits and other non-current liabilities:			
Deferred tax liabilities	438,486	396,357	413,209
Regulatory liabilities	288,131	263,876	278,382
Pension and other postretirement benefit liabilities	189,003	132,053	201,530
Derivative instruments	3,947	13,914	6,536
Other non-current liabilities	79,461	67,514	76,265
Total deferred credits and other non-current liabilities	999,028	873,714	975,922
Commitments and contingencies (see Note 13)			
Total capitalization and liabilities	$ 2,727,262	$ 2,571,553	$ 2,746,574

See Notes to Consolidated Financial Statements.

PNY 10-Q 4/30/2012

Section 1: 10-Q (FORM 10-Q)

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549

FORM 10-Q

(Mark One)

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended April 30, 2012

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from _____to _____

Commission File Number 1-6196

Piedmont Natural Gas Company, Inc.

(Exact name of registrant as specified in its charter)

North Carolina	56-0556998
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
4720 Piedmont Row Drive, Charlotte, North Carolina	28210
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code (704) 364-3120

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☑ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ☑ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ☐ Yes ☑ No

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at June 1, 2012
Common Stock, no par value	71,903,935

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Piedmont Natural Gas Company, Inc. and Subsidiaries
Consolidated Balance Sheets (Unaudited)
(In thousands)

	April 30, 2012	October 31, 2011
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Stockholders' equity:		
Cumulative preferred stock — no par value — 175 shares authorized	$ —	$ —
Common stock — no par value — shares authorized: 200,000; shares outstanding: 71,879 in 2012 and 72,318 in 2011	431,140	446,791
Retained earnings	634,563	550,584
Accumulated other comprehensive loss	(892)	(452)
Total stockholders' equity	1,064,811	996,923
Long-term debt	975,000	675,000
Total capitalization	2,039,811	1,671,923
Current Liabilities:		
Short-term debt	80,000	331,000
Trade accounts payable	75,942	85,721
Other accounts payable	27,434	43,959
Accrued interest	20,043	20,038
Customers' deposits	24,689	25,462
Deferred income taxes	31,269	—
General taxes accrued	10,487	21,262
Amounts due to customers	4,722	2,617
Other current liabilities	4,836	4,073
Total current liabilities	279,422	534,132
Noncurrent Liabilities:		
Deferred income taxes	565,701	512,961
Unamortized federal investment tax credits	1,829	2,004
Accumulated provision for postretirement benefits	14,743	14,671
Cost of removal obligations	479,927	466,000
Other noncurrent liabilities	42,766	40,850
Total noncurrent liabilities	1,104,966	1,036,486
Commitments and Contingencies (Note 9)		
Total	$ 3,424,199	$ 3,242,541

See notes to consolidated financial statements.

SJI 10-Q 3/31/2012

Section 1: 10-Q (SOUTH JERSEY INDUSTRIES 10-Q 3.31.12)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 10-Q

(Mark one)

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended **March 31, 2012**

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____ to _____

Commission File Number **1-6364**

SOUTH JERSEY INDUSTRIES, INC.

(Exact name of registrant as specified in its charter)

New Jersey	**22-1901645**
(State of incorporation)	(IRS employer identification no.)

1 South Jersey Plaza, Folsom, NJ 08037
(Address of principal executive offices, including zip code)

(609) 561-9000
(Registrant's telephone number, including area code)

Common Stock	
($1.25 par value per share)	**New York Stock Exchange**
(Title of each class)	(Name of exchange on which registered)

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of May 1, 2012 there were 30,400,671 shares of the registrant's common stock outstanding.

SOUTH JERSEY INDUSTRIES, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)
(In Thousands)

	March 31, 2012	December 31, 2011
Capitalization and Liabilities		
Equity:		
Common Stock	$ 37,887	$ 37,765
Premium on Common Stock	276,677	273,303
Treasury Stock (at par)	(145)	(193)
Accumulated Other Comprehensive Loss	(30,179)	(28,438)
Retained Earnings	383,552	341,677
Total Equity	667,792	624,114
Long-Term Debt	426,400	424,213
Total Capitalization	1,094,192	1,048,327
Current Liabilities:		
Notes Payable	344,700	321,400
Current Portion of Long-Term Debt	—	2,187
Accounts Payable	128,203	153,666
Customer Deposits and Credit Balances	18,371	24,914
Environmental Remediation Costs	18,709	24,721
Taxes Accrued	6,102	3,168
Derivatives - Energy Related Liabilities	36,712	38,738
Deferred Income Taxes - Net	3,794	—
Deferred Contract Revenues	781	996
Dividends Payable	12,200	—
Interest Accrued	4,905	6,408
Pension Benefits	1,240	1,275
Other Current Liabilities	7,075	10,498
Total Current Liabilities	582,792	587,971
Deferred Credits and Other Noncurrent Liabilities:		
Deferred Income Taxes - Net	290,594	295,434
Investment Tax Credits	833	905
Pension and Other Postretirement Benefits	86,153	109,021
Environmental Remediation Costs	73,962	69,439
Asset Retirement Obligations	29,490	29,430
Derivatives - Energy Related Liabilities	5,220	7,367
Derivatives - Other	12,084	14,046
Regulatory Liabilities	48,822	48,311
Finance Obligation	22,323	22,549
Other	13,910	14,710
Total Deferred Credits and Other Noncurrent Liabilities	583,391	611,212
Commitments and Contingencies (Note 11)		
Total Capitalization and Liabilities	$ 2,260,375	$ 2,247,510

The accompanying notes are an integral part of the unaudited condensed consolidated financial statements.

SWX 10-Q 3/31/2012

Section 1: 10-Q (FORM 10-Q)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

Form 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2012

Commission File Number 1-7850

SOUTHWEST GAS CORPORATION

(Exact name of registrant as specified in its charter)

California (State or other jurisdiction of incorporation or organization)	88-0085720 (I.R.S. Employer Identification No.)
5241 Spring Mountain Road Post Office Box 98510 Las Vegas, Nevada (Address of principal executive offices)	89193-8510 (Zip Code)

Registrant's telephone number, including area code: (702) 876-7237

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes X No __

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes X No __

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," "non-accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act.
Large accelerated filer X Accelerated filer __ Non-accelerated filer __ Smaller reporting company __

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes __ No X

Indicate the number of shares outstanding of each of the issuer's classes of common stock as of the latest practicable date.

Common Stock, $1 Par Value, 46,112,072 shares as of April 27, 2012.

PART I – FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

SOUTHWEST GAS CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS
(Thousands of dollars, except par value)
(Unaudited)

	MARCH 31, 2012	DECEMBER 31, 2011
ASSETS		
Utility plant:		
Gas plant	$ 4,842,972	$ 4,811,050
Less: accumulated depreciation	(1,667,904)	(1,638,091)
Acquisition adjustments, net	1,045	1,091
Construction work in progress	58,817	44,894
Net utility plant	3,234,930	3,218,944
Other property and investments	220,847	192,004
Restricted cash	-	12,785
Current assets:		
Cash and cash equivalents	218,060	21,937
Accounts receivable, net of allowances	210,735	209,246
Accrued utility revenue	43,700	70,300
Income taxes receivable, net	2,299	7,793
Deferred income taxes	33,815	53,435
Deferred purchased gas costs	-	2,323
Prepaids and other current assets	77,330	96,598
Total current assets	585,939	461,632
Deferred charges and other assets	395,381	390,642
Total assets	$ 4,437,097	$ 4,276,007
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common stock, $1 par (authorized - 60,000,000 shares; issued and outstanding - 46,110,072 and 45,956,088 shares)	$ 47,740	$ 47,586
Additional paid-in capital	823,460	821,640
Accumulated other comprehensive income (loss), net	(46,840)	(49,331)
Retained earnings	471,265	406,125
Total Southwest Gas Corporation equity	1,295,625	1,226,020
Noncontrolling interest	(1,073)	(989)
Total equity	1,294,552	1,225,031
Long-term debt, less current maturities	1,188,076	930,858
Total capitalization	2,482,628	2,155,889
Current liabilities:		
Current maturities of long-term debt	205,055	322,618
Accounts payable	132,544	186,755
Customer deposits	83,138	83,839
Accrued general taxes	58,565	42,102
Accrued interest	19,305	16,699
Deferred purchased gas costs	75,715	72,426
Other current liabilities	115,012	123,129
Total current liabilities	689,334	847,568
Deferred income taxes and other credits:		
Deferred income taxes and investment tax credits	578,563	557,118
Taxes payable	759	828
Accumulated removal costs	239,000	233,000
Other deferred credits	446,813	481,604
Total deferred income taxes and other credits	1,265,135	1,272,550
Total capitalization and liabilities	$ 4,437,097	$ 4,276,007

The accompanying notes are an integral part of these statements.

Response No. MCC-092
Attachment I

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AGL RESOURCES INC

FORM 10-K
(Annual Report)

Filed 02/22/12 for the Period Ending 12/31/11

Address	TEN PEACHTREE PLACE ATLANTA, GA 30309
Telephone	4045844000
CIK	0001004155
Symbol	GAS
SIC Code	4924 - Natural Gas Distribution
Industry	Natural Gas Utilities
Sector	Utilities
Fiscal Year	12/31

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In connection with the Nicor merger, the headquarters of our distribution operations segment moved to Naperville, Illinois during December 2011 and we agreed not to initiate a rate proceeding that would increase our base rates effective prior to December 7, 2014. We have committed to maintain 2,070 full-time equivalent employees involved in the operation of Nicor Gas for a period of three years and maintain the personnel numbers in specific areas of safety oversight of the Nicor Gas system for a period of at least five years. Additionally, we are required to maintain the same level of corporate philanthropy within the communities that Nicor Gas serves.

See the following discussions for more information on the impacts of the Nicor merger on our business. Additionally, see the Executive Summary within Management's Discussion and Analysis of Financial Condition and Results of Operations, as well as Note 3 to our consolidated financial statements under Item 8 herein, for additional information on the merger. During 2011, we recorded approximately $68 million ($55 million net of tax) of transaction expenses associated with the merger with Nicor. These costs are expensed as incurred. The effects of Nicor's results of operations and financial condition on our 2011 results include activity from December 10, 2011 through December 31, 2011.

Nature of Our Business

We are an energy services holding company whose principal business is the distribution of natural gas in seven states - Illinois, Georgia, Virginia, New Jersey, Florida, Tennessee and Maryland – through our seven natural gas distribution utilities, including, as a result of the Nicor merger, Nicor Gas. At December 31, 2011, our seven utilities served approximately 4.5 million end-use customers.

In addition to our primary business of the distribution of natural gas, we are involved in several related and complementary businesses. Our retail operations segment serves more than one million retail customers and markets natural gas and related home services to end-use customers in Georgia, Illinois, Ohio, Florida and New York. Our wholesale services segment provides natural gas storage arbitrage and related activities, natural gas asset management and related logistics activities for each of our utilities as well as for non-affiliated companies. Our midstream operations segment provides natural gas storage arbitrage and related activities and engages in the development and operation of high-deliverability natural gas storage assets.

As a result of the Nicor merger we are also involved in the shipping industry through our cargo shipping segment, which owns and operates Tropical Shipping, one of the largest containerized cargo carriers serving the Bahamas and the Caribbean.

In connection with the completion of the Nicor merger on December 9, 2011, we revised our operating segments to be the following five operating and reporting segments — distribution operations, retail operations, wholesale services, midstream operations, cargo shipping and one non-operating segment — other. These segments are consistent with how management views and manages our businesses. For additional information on our segments, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Results of Operations" and Note 13 to our consolidated financial statements under Item 8 herein.

Distribution Operations

Our distribution operations segment is the largest component of our business and includes seven natural gas local distribution utilities. These utilities construct, manage and maintain intrastate natural gas pipelines and distribution facilities and include:

Utility	State	Number of customers (in thousands)	Approximate miles of pipe
Nicor Gas (1)	Illinois	2,188	34,000
Atlanta Gas Light	Georgia	1,541	32,250
Virginia Natural Gas	Virginia	278	5,500
Elizabethtown Gas	New Jersey	276	3,150
Florida City Gas	Florida	103	3,450
Chattanooga Gas	Tennessee	62	1,600
Elkton Gas	Maryland	6	100
Total		4,454	80,050

(1) Customers as of December 31, 2011.

The focus on the design of our distribution operations is the delivery of safe and reliable natural gas to our end-users. In integrating Nicor Gas into our existing distribution operations, we plan to focus on the standardization of operational processes along with continuing to focus on delivering superior customer service.

Utility Regulation and Rate Design

Rate Structures Our utilities operate subject to regulations and oversight of the state regulatory agencies in each of the seven states served by our utilities with respect to rates charged to our customers, maintenance of accounting records and various service and safety matters. Rates charged to our customers vary according to customer class (residential, commercial or industrial) and rate jurisdiction. These agencies approve rates designed to provide us the opportunity to generate revenues to recover all prudently incurred costs, including a return on rate base sufficient to pay interest on debt and provide a reasonable return for our shareholders. Rate base generally consists of the original cost of utility plant in service, working capital and certain other assets; less accumulated depreciation on utility plant in service and net deferred income tax liabilities, and may include certain other additions or deductions.

The natural gas market for Atlanta Gas Light was deregulated in 1997. Accordingly, Marketers, rather than a traditional utility, sell natural gas to end-use customers in Georgia and handle customer billing functions. The Marketers file their rates monthly with the Georgia Commission. As a result of operating in a deregulated environment, Atlanta Gas Light's role includes:

- distributing natural gas for Marketers
- constructing, operating and maintaining the gas system infrastructure, including responding to customer service calls and leaks
- reading meters and maintaining underlying customer premise information for Marketers
- planning and contracting for capacity on interstate transportation and storage systems

Atlanta Gas Light earns revenue by charging rates to its customers based primarily on monthly fixed charges that are periodically adjusted. The Marketers add these fixed charges to customer bills. This mechanism, called a straight-fixed-variable rate design, minimizes the seasonality of Atlanta Gas Light’s revenues since the monthly fixed charge is not volumetric or directly weather dependent.

With the exception of Atlanta Gas Light, the earnings of our regulated utilities can be affected by customer consumption patterns that are a function of weather conditions and price levels for natural gas. Specifically, customer demand substantially increases during the Heating Season when natural gas is used for heating purposes. We have various mechanisms, such as weather normalization mechanisms at some of our utilities which limit our exposure to weather changes within typical ranges in the utilities’ respective service areas.

All of our utilities, excluding Atlanta Gas Light, are authorized to use natural gas cost recovery mechanisms that allow them to adjust their rates to reflect changes in the wholesale cost of natural gas and to ensure they recover all of the costs prudently incurred in purchasing gas for their customers. Since Atlanta Gas Light does not sell natural gas directly to its end-use customers, it does not need or utilize a natural gas cost recovery mechanism. However, Atlanta Gas Light does maintain inventory for the Marketers in Georgia and recovers the cost of this gas through recovery mechanisms approved by the Georgia Commission.

In addition to natural gas recovery mechanisms, we have other cost recovery mechanisms, such as riders, which vary by utility but allow us to recover certain costs such as environmental remediation and energy efficiency plans.

In traditional rate designs, utilities recover a significant portion of their fixed customer service and pipeline infrastructure costs based on assumed natural gas volumes used by our customers. Three of our utilities have “decoupled” regulatory mechanisms in place that encourage conservation. We believe that separating, or decoupling, the recoverable amount of these fixed costs from the customer throughput volumes, or amounts of natural gas used by our customers, allows us to encourage our customers’ energy conservation and ensures a more stable recovery of our fixed costs.

The following table provides regulatory information for our six largest utilities.

	Nicor Gas	Atlanta Gas Light	Virginia Natural Gas	Elizabethtown Gas	Florida City Gas	Chattanooga Gas
Authorized return on rate base (1)	8.09%	8.10%	7.38%	7.64%	7.36%	7.41%
Estimated 2011 return on rate base (2)	N/A	8.33%	8.15%	8.84%	5.74%	8.43%
Authorized return on equity (1)	10.17%	10.75%	10.00%	10.30%	11.25%	10.05%
Estimated 2011 return on equity (2)	N/A	11.20%	11.97%	12.81%	8.53%	12.24%
Authorized rate base % of equity (1)	51.1%	51.0%	45.4%	47.9%	36.8%	46.1%
Rate base included in 2011 return on equity (in millions) (2)	$ 1,485	$ 1,317	$ 516	$ 476	$ 163	$ 92
Weather normalization (3)			✓	✓		✓
Decoupled or straight-fixed-variable rates (4)		✓				✓
Regulatory infrastructure program rates (5)		✓		✓		
Bad debt rider (6)	✓					
Synergy sharing policy (7)		✓				
Last decision on change in rates (8)	Oct. 2009	Oct. 2010	Dec 2011	Dec. 2009	N/A	May 2010

(1) The authorized return on rate base, return on equity, and percentage of equity were those authorized as of December 31, 2011.
(2) Estimates based on principles consistent with utility ratemaking in each jurisdiction.
(3) Involves regulatory mechanisms that allow us to recover our costs in the event of unseasonal weather, but are not direct offsets to the potential impacts of weather and customer consumption on earnings. These mechanisms are designed to help stabilize operating results by increasing base rate amounts charged to customers when weather is warmer than normal and decreasing amounts charged when weather is colder than normal.
(4) Decoupled and straight-fixed-variable rate designs allow for the recovery of fixed customer service costs separately from assumed natural gas volumes used by our customers. The decoupled rate design for Virginia Natural Gas expired in December 2011.
(5) Includes programs that update or expand our distribution systems and liquefied natural gas facilities.
(6) Involves the recovery (or refund) of the amount of bad debt expense over (or under) an established benchmark expense.
(7) Involves the recovery of 50% of net synergy savings achieved on future acquisitions.
(8) In connection with the Nicor merger, we agreed not to initiate a rate proceeding that would increase our base rates for Nicor Gas effective prior to December 9, 2014.

Recent Regulatory Actions

Nicor Gas In May 2011, the Illinois Commission approved an energy efficiency plan for Nicor Gas pursuant to an Illinois law that requires local gas distribution utilities to establish plans to achieve specified energy savings goals and provides utilities with a rider to collect the costs from customers. Under its approved plan, we estimate that Nicor Gas would bill approximately $155 million to customers under the rider, over a three year period which commenced June 1, 2011, to fund the costs of various energy savings programs identified in the filing. This new energy efficiency plan rider replaced the rider previously in effect. The costs under the rider are subject to annual review by the Illinois Commission.

On July 1, 2009, Nicor Gas filed a petition seeking re-approval from the Illinois Commission of the operating agreement that governs many inter-company transactions between Nicor Gas and its affiliates. The petition was filed pursuant to a requirement contained in the Illinois Commission order approving Nicor Gas's most recent general rate increase and requested that the operating agreement be re-approved without change. A number of parties intervened in the proceeding (the "operating agreement proceeding") and sought modifications on a prospective basis to the operating agreement. Among the proposals were several by the Illinois Commission Staff and intervenors that would preclude Nicor Gas from continuing to provide certain services to support warranty products that are sold by Nicor Services. Specifically, Nicor Services had used Nicor Gas personnel to assist in some sales solicitation for these warranty products. The Illinois Commission was required to evaluate future transactions between Nicor Gas and its affiliates in connection with the joint application of AGL Resources, Nicor and Nicor Gas for approval of the merger of AGL Resources and Nicor (the "merger proceeding"). The Illinois Commission Administrative Law Judge assigned to the merger proceeding decided to address the matters raised in the operating agreement proceeding in the merger proceeding. As a result, Nicor Gas is no longer permitted to use its call center personnel to solicit its affiliates' products, most notably the warranty products. This is not expected to have a material impact on our results of operations, cash flows and financial condition.

On January 1, 2000, Nicor Gas instituted a PBR plan for natural gas costs. Under the PBR plan, Nicor Gas' total gas supply costs were compared to a market-sensitive benchmark. Savings and losses relative to the benchmark were determined annually and shared equally with sales customers. The PBR plan was terminated effective January 1, 2003. The PBR plan is currently under review by the Illinois Commission as there are allegations that Nicor Gas acted improperly in connection with the PBR plan. In February 2012, we committed to a stipulated resolution of issues with the Illinois Commission, which includes crediting Nicor Gas customers $64 million, but does not constitute an admission of fault. The stipulated resolution is subject to review and approval by the Illinois Commission. The Citizens Utility Board and the Illinois Attorney General's Office are not parties to the stipulation resolution and continue to pursue their claims in this proceeding. Evidentiary hearings on this matter are scheduled to begin on February 28, 2012. We do not expect the stipulated resolution to affect our 2011 or 2012 Consolidated Statements of Income, as the $64 million proposed credit is consistent with the estimated liability we recorded for this matter as part of our accounting for the merger with Nicor. For more information on the PBR plan see Note 11 to our consolidated financial statements under Item 8 herein.

Investment and Other Tax Credits Deferred investment tax credits associated with distribution operations are included as a regulatory liability in our Consolidated Statements of Financial Position. These investment tax credits are being amortized over the estimated life of the related properties as credits to income in accordance with regulatory requirements.

Accumulated Deferred Income Tax Assets and Liabilities As noted above, we report some of our assets and liabilities differently for financial accounting purposes than we do for income tax purposes. We report the tax effects of the differences in those items as deferred income tax assets or liabilities in our Consolidated Statements of Financial Position. We measure these deferred income tax assets and liabilities using enacted income tax rates.

Regulatory Income Tax Liability For our regulated utilities we also measure deferred income tax assets and liabilities using enacted income tax rates. Thus, when the statutory income tax rate declines before a temporary difference has fully reversed, the deferred income tax liability must be reduced to reflect the newly enacted income tax rates. In accordance with authoritative guidance related to rate-regulated entities, the amount of such a reduction is transferred to our regulatory income tax liability, which we are amortizing over the lives of the related properties as the temporary difference reverses or approximately 30 years.

A deferred income tax liability is not recorded on undistributed foreign earnings that are expected to be indefinitely reinvested offshore. We consider, among other factors, actual cash investments offshore as well as projected cash requirements in making this determination. Changes in our investment or repatriation plans or circumstances could result in a different deferred income tax liability.

Tax Benefits The authoritative guidance related to income taxes requires us to determine whether tax benefits claimed or expected to be claimed on our tax return should be recorded in our consolidated financial statements. Under this guidance, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. This guidance also addresses derecognition, classification, interest and penalties on income taxes, and accounting in interim periods.

Uncertain Tax Positions We recognize accrued interest related to uncertain tax positions in interest expense and penalties in operating expense in the Consolidated Statements of Income. As of December 31, 2011, we did not have a liability recorded for payment of interest and penalties associated with uncertain tax positions.

Tax Collections We do not collect income taxes from our customers on behalf of governmental authorities. We collect and remit various taxes on behalf of various governmental authorities. We record these amounts in our Consolidated Statements of Financial Position. In other instances, we are allowed to recover from customers other taxes that are imposed upon us. We record such taxes as operating expense and record the corresponding customer charges as revenue. These taxes were immaterial for all periods presented.

Revenues

Distribution operations We record revenues when services are provided to customers. Those revenues are based on rates approved by the state regulatory commissions of our utilities.

As required by the Georgia Commission, in July 1998, Atlanta Gas Light began billing Marketers in equal monthly installments for each residential, commercial and industrial customer's distribution costs. As required by the Georgia Commission, effective February 1, 2001, Atlanta Gas Light implemented a seasonal rate design for the calculation of each residential customer's annual straight-fixed-variable (SFV) capacity charge, which is billed to Marketers and reflects the historic volumetric usage pattern for the entire residential class. Generally, this change results in residential customers being billed by Marketers for a higher capacity charge in the winter months and a lower charge in the summer months. This requirement has an operating cash flow impact but does not change revenue recognition. As a result, Atlanta Gas Light continues to recognize its residential SFV capacity revenues for financial reporting purposes in equal monthly installments.

All of our utilities, with the exception of Atlanta Gas Light, have rate structures include volumetric rate designs that allow recovery of costs through gas usage. Revenues from sales and transportation services are recognized in the same period in which the related volumes are delivered to customers. Revenues from residential and certain commercial and industrial customers are recognized on the basis of scheduled meter readings. Additionally, revenues are recorded for estimated deliveries of gas not yet billed to these customers, from the last bill date to the end of the accounting period. These are included in the Consolidated Statements of Financial Position as unbilled revenue. For other commercial and industrial customers and all wholesale customers, revenues are based on actual deliveries to the end of the period.

The tariffs for Virginia Natural Gas, Elizabethtown Gas and Chattanooga Gas contain WNA's that partially mitigate the impact of unusually cold or warm weather on customer billings and operating margin. The WNA's purpose is to reduce the effect of weather on customer bills by reducing bills when winter weather is colder than normal and increasing bills when weather is warmer than normal. In addition, the tariffs for Chattanooga Gas and Elkton Gas contain revenue normalization mechanisms that mitigate the impact of conservation and declining customer usage.

PIVOTAL UTILITY HOLDINGS, INC. d/b/a
ELKTON GAS

GAS SERVICE TARIFF

GAS – P.S.C. – MD NO. 13

REVISED 12/1/10

THE FOLLOWING PAGES HAVE BEEN REVISED:

Second Revised Page No. 1
First Revised Page Nos. 22, 26, 30 and 34

THE FOLLOWING PAGES HAVE BEEN ADDED:

Original Page Nos. 34 A and 34 B

REVENUE NORMALIZATION ADJUSTMENT CLAUSE (RNA)

PROVISION FOR ADJUSTMENT

The RNA shall apply to heating customers as defined and tracked by the Company. The Residential RNA (RNA-R) shall be applicable to all heating customers in Rate Schedules RS. The Commercial RNA (RNA-C) shall be applicable to all heating customers in Rate Schedules CS and CT.

METHOD OF DETERMINING RNA CHARGES

The RNA charge shall be determined as follows:

A. Definition of Terms as Used Herein

1. Monthly Normalized Revenue Per Customer (MNRC) the revenue derived from the Customer and Distribution Charges authorized in the Company s last rate case, adjusted for any subsequent incremental applicable taxes and/or assessments, divided by the number of applicable Customers. The average monthly revenue per heating Customer are as follows:

	RNA-R	RNA-C
September	$10.75	$52.51
October	$15.68	$88.88
November	$24.88	$111.67
December	$35.58	$147.98
January	$40.10	$167.40
February	$39.48	$244.11
March	$37.36	$228.91
April	$18.54	$92.37
May	$12.56	$40.37
June	$9.66	$45.65
July	$8.98	$42.67
August	$9.20	$56.26
Total	$262.77	$1,318.78

REVENUE NORMALIZATION ADJUSTMENT CLAUSE (RNA)
(CONTINUED)

METHOD OF DETERMINING RNA CHARGES (Continued)

A. Definition of Terms as Used Herein (Continued)

2. Actual Customer Count (ACC) - the number of heating customers billed during a month.

3. Monthly Normalized Revenues - the MNRC times that months ACC.

4. Actual Accounting Revenues (AAR) - the Company s total monthly reported revenues for the heating customers to which the RNA applies.

B. Determination of the RNA Rate

Separately for RNA-R and RNA-C, at the end of each month a calculation shall be made that determines the level by which the Monthly Normalized Revenues differed from the Actual Accounting Revenues as follows:

The monthly excess or deficiency shall be determined by deriving the Monthly Normalized Revenue and subtracting that month's Actual Accounting Revenues. The sum of the month's excesses and/or deficiencies plus any prior months true-up shall be divided by the applicable RNA volumes, the rolling twelve month billing determinants similar to the determination of the PGA, in which the excess or deficiency is to be charged or credited to the Customers subject to this clause. The following illustrates the derivation of the respective RNA-R and RNA-C rates:

RNA rate ((MNRC ACC) AAR /- true-up) / RNA volumes

TRACKING THE OPERATION AND IMPLEMENTATION OF THE RNA CLAUSE

The revenues billed, or credits applied, net of taxes and assessments, through the application of the RNA rate shall be applied against the revenue excess or deficiency from the preceding RNA month and prior month s balances, if any. The filing and implementation of the RNA rate shall be concurrent with the PGA filing based on the latest available actual monthly accounting data.

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ATMOS ENERGY CORP

FORM 10-K
(Annual Report)

Filed 11/22/11 for the Period Ending 09/30/11

Address	1800 THREE LINCOLN CTR 5430 LBJ FREEWAY DALLAS, TX 75240
Telephone	9729349227
CIK	0000731802
Symbol	ATO
SIC Code	4924 - Natural Gas Distribution
Industry	Natural Gas Utilities
Sector	Utilities
Fiscal Year	09/30

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Atmos Energy Mid-Tex Division. Our Mid-Tex Division serves approximately 550 incorporated and unincorporated communities in the north-central, eastern and western parts of Texas, including the Dallas/Fort Worth Metroplex. The governing body of each municipality we serve has original jurisdiction over all gas distribution rates, operations and services within its city limits, except with respect to sales of natural gas for vehicle fuel and agricultural use. The Railroad Commission of Texas (RRC) has exclusive appellate jurisdiction over all rate and regulatory orders and ordinances of the municipalities and exclusive original jurisdiction over rates and services to customers not located within the limits of a municipality.

Prior to fiscal 2008, this division operated under one system-wide rate structure. However, in fiscal 2008, we reached a settlement with cities representing approximately 80 percent of this division's customers (Settled Cities) that has allowed us, beginning in fiscal 2008, to update rates for customers in these cities through an annual rate review mechanism (RRM). Rates for the remaining 20 percent of this division's customers, primarily the City of Dallas, continue to be updated through periodic formal rate proceedings and filings made under Texas' Gas Reliability Infrastructure Program (GRIP). GRIP allows us to include in our rate base annually approved capital costs incurred in the prior calendar year provided that we file a complete rate case at least once every five years. In June 2011, we reached an agreement with the City of Dallas to enter into the Dallas Annual Rate Review (DARR). This rate review provides for an annual rate review without the necessity of filing a general rate case. The first filing made under this mechanism will be in January 2012.

Atmos Energy Kentucky/Mid-States Division. Our Kentucky/Mid-States Division operates in more than 420 communities across Georgia, Illinois, Iowa, Kentucky, Missouri, Tennessee and Virginia. The service areas in these states are primarily rural; however, this division serves Franklin, Tennessee and other suburban areas of Nashville. We update our rates in this division through periodic formal rate filings made with each state's public service commission.

In May 2011, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 189 communities, some of which of the Missouri communities are located in our Atmos Energy Colorado-Kansas Division.

Atmos Energy Louisiana Division. In Louisiana, we serve nearly 300 communities, including the suburban areas of New Orleans, the metropolitan area of Monroe and western Louisiana. Direct sales of natural gas to industrial customers in Louisiana, who use gas for fuel or in manufacturing processes, and sales of natural gas for vehicle fuel are exempt from regulation and are recognized in our nonregulated segment. Our rates in this division are updated annually through a rate stabilization clause filing without filing a formal rate case.

Atmos Energy West Texas Division. Our West Texas Division serves approximately 80 communities in West Texas, including the Amarillo, Lubbock and Midland areas. Like our Mid-Tex Division, each municipality we serve has original jurisdiction over all gas distribution rates, operations and services within its city limits, with the RRC having exclusive appellate jurisdiction over the municipalities and exclusive original jurisdiction over rates and services provided to customers not located within the limits of a municipality. Prior to fiscal 2008, rates were updated in this division through formal rate proceedings. However, the West Texas Division entered into agreements with its West Texas service areas during fiscal 2008 and its Amarillo and Lubbock service areas during fiscal 2009 to update rates for customers in these service areas through an RRM.

Atmos Energy Mississippi Division. In Mississippi, we serve about 110 communities throughout the northern half of the state, including the Jackson metropolitan area. Our rates in the Mississippi Division are updated annually through a stable rate filing without filing a formal rate case.

Atmos Energy Colorado-Kansas Division. Our Colorado-Kansas Division serves approximately 170 communities throughout Colorado and Kansas and parts of Missouri, including the cities of Olathe, Kansas, a suburb of Kansas City and Greeley, Colorado, located near Denver. We update our rates in this division through periodic formal rate filings made with each state's public service commission.

The following table provides a jurisdictional rate summary for our regulated operations. This information is for regulatory purposes only and may not be representative of our actual financial position.

Division	Jurisdiction	Effective Date of Last Rate/GRIP Action	Rate Base (thousands) (1)	Authorized Rate of Return (1)	Authorized Return on Equity (1)
Atmos Pipeline — Texas	Texas	05/01/2011	$807,733	9.36%	11.80%
Atmos Pipeline — Texas — GRIP	Texas	08/01/2011	816,976	9.36%	11.80%
Colorado-Kansas	Colorado	01/04/2010	86,189	8.57%	10.25%
	Kansas	08/01/2010	144,583	(2)	(2)
Kentucky/Mid-States	Georgia	03/31/2010	96,330 (3)	8.61%	10.70%
	Illinois	11/01/2000	24,564	9.18%	11.56%
	Iowa	03/01/2001	5,000	(2)	11.00%
	Kentucky	06/01/2010	208,702 (4)	(2)	(2)
	Missouri	09/01/2010	66,459	(2)	(2)
	Tennessee	04/01/2009	190,100	8.24%	10.30%
	Virginia	11/23/2009	36,861	8.48%	9.50% - 10.50%
Louisiana	Trans LA	04/01/2011	93,260	8.37%	10.00% - 10.80%
	LGS	07/01/2011	273,775	8.56%	10.40%
Mid-Tex — Settled Cities	Texas	09/01/2011	1,389,187 (5)	8.29%	9.70%
Mid-Tex — Dallas	Texas	06/22/2011	1,268,601 (5)	8.45%	10.10%
Mid-Tex — Environs GRIP	Texas	06/27/2011	1,268,601 (5)	8.60%	10.40%
Mississippi	Mississippi	04/05/2011	239,197	(2)	9.86%
West Texas	Amarillo	08/01/2011	(2)	(2)	9.60%
	Lubbock	09/09/2011	60,892	8.19%	9.60%
	West Texas	08/01/2011	146,039	8.19%	9.60%

Division	Jurisdiction	Authorized Debt/ Equity Ratio	Bad Debt Rider [6]	WNA	Performance-Based Rate Program [7]	Customer Meters
Atmos Pipeline — Texas	Texas	50/50	No	N/A	N/A	N/A
Colorado-Kansas	Colorado	50/50	Yes[8]	No	No	110,709
	Kansas	(2)	Yes	Yes	No	128,679
Kentucky/Mid-States	Georgia	52/48	No	Yes	Yes	63,897
	Illinois	67/33	No	No	No	22,778
	Iowa	57/43	No	No	No	4,334
	Kentucky	(2)	Yes	Yes	Yes	176,246
	Missouri	49/51	No	No	No	56,643
	Tennessee	52/48	Yes	Yes	Yes	133,634
	Virginia	51/49	Yes	Yes	No	23,310
Louisiana	Trans LA	52/48	No	Yes	No	75,813
	LGS	52/48	No	Yes	No	277,838
Mid-Tex — Settled Cities	Texas	50/50	Yes	Yes	No	1,259,042
Mid-Tex — Dallas & Environs	Texas	51/49	Yes	Yes	No	314,760
Mississippi	Mississippi	50/50	No	Yes	No	266,074
West Texas	Amarillo	52/48	Yes	Yes	No	70,431
	Lubbock	52/48	Yes	Yes	No	73,748
	West Texas	52/48	Yes	Yes	No	155,255

(1) The rate base, authorized rate of return and authorized return on equity presented in this table are those from the most recent rate case or GRIP filing for each jurisdiction. These rate bases, rates of return and returns on equity are not necessarily indicative of current or future rate bases, rates of return or returns on equity.

(2) A rate base, rate of return, return on equity or debt/equity ratio was not included in the respective state commission's final decision.

(3) Georgia rate base consists of $60.2 million included in the March 2010 rate case and $36.1 million included in the October 2011 Pipeline Replacement Program (PRP) surcharge. A total of $36.1 million of the Georgia rate base amount was awarded in the latest PRP annual filing with an effective date of October 1, 2011, an authorized rate of return of 8.56 percent and an authorized return on equity of 10.70 percent.

(4) Kentucky rate base consists of $184.7 million included in the June 2010 rate case and $24.0 million included in the October 2011 PRP surcharge. A total of $24.0 million of the Kentucky rate base amount was awarded in the latest PRP annual filing with an effective date of October 1, 2011, an authorized rate of return of 8.74 percent and an authorized return on equity of 10.50 percent.

(5) The Mid-Tex Rate Base amounts for the Settled Cities and Dallas & Environs areas represent "system-wide", or 100 percent, of the Mid-Tex Division's rate base.

(6) The bad debt rider allows us to recover from ratepayers the gas cost portion of uncollectible accounts.

(7) The performance-based rate program provides incentives to natural gas utility companies to minimize purchased gas costs by allowing the utility company and its customers to share the purchased gas costs savings.

(8) The recovery of the gas portion of uncollectible accounts gas cost adjustment has been approved for a two-year pilot program.

MARGIN LOSS RECOVERY RIDER

I. Provision for Adjustment

The rates per Ccf (100 cubic feet) of gas set forth in all of the Rate Schedules of ATMOS Energy Corporation, (the "Company") shall be increased by an amount hereinafter described, which amount is called the " Margin Loss Recovery Factor."

II. Computation and Application of Margin Loss Recovery Factor

The Margin Loss Recovery Factor for the Company's Georgia service areas shall be computed to the nearest one-hundredth cent per Ccf in the following manner:

1. The Company shall recover forty percent (40%) of the margin loss from firm customers, thirty-five percent (35%) from interruptible customers, and the Company shall absorb the remaining twenty-five percent (25%).

2. The recovery factor shall be determined by dividing the margin loss from the recovery period by the billing determinants approved in the Company's most recent rate proceeding.

3. The recovery factor shall be applied to currently approved commodity charges within all Firm and Interruptible Rate Schedules.

III. Balancing Adjustment

A. The balancing adjustment shall be used to reconcile the difference between the amount of margin loss actually collected and the amount of margin loss that should have been collected.

B. The balancing adjustment shall be calculated on the prior recovery period, and either increase or decrease the revised recovery factor.

IV. The Company shall file as directed by the Georgia Public Service Commission a detailed report stating the amount of margin loss to be recovered. The report shall include all calculations used by the Company to determine the margin loss amount.

GRAM

Georgia Rate Adjustment Mechanism ("GRAM")

I. **Applicable**

To all gas sold and transported under tariff services excluding special contracts.

II. **Purpose**

This Georgia Rate Adjustment Mechanism ("GRAM") is designed to implement an annual earnings review and non-gas-cost revenue ("base rate revenue") adjustment (first authorized by the Georgia Public Service Commission in Docket 34734). If, through the implementation of the provisions of this mechanism, it is determined that rates should be decreased or increased, then rates will be adjusted accordingly in the manner set forth herein. The rate adjustments implemented under this mechanism will reflect changes in the Company's base rate revenues, cost of service, and rate base.

III. **Definitions**

A) **Annual Evaluation Date** shall be the date the Company will make its annual GRAM filing. The Annual Evaluation Date shall be no later than October 1 of each year, unless: (a) the Company files either a comprehensive rate case prior to October 1: or (b) the Company files a notice with the Commission of its intent to file a comprehensive rate case prior to the end of such calendar year. The annual filing under this mechanism shall be made in electronic form where practicable.

B) **Historic Test Year** is defined as the twelve month period ending June 30 of each calendar year in which an Annual Evaluation Date occurs.

C) **Forward Looking Test Year** is defined as the twelve month period ending August 31 of each year in which an Annual Evaluation Date occurs during the same 12-month period.

D) **Rate Effective Period** is defined as the twelve month period in which base rates determined under this mechanism ("**Effective Rates**") shall be in effect. The Effective Rates shall apply to bills rendered from February 1 to January 31, unless the beginning of the Rate Effective Period is delayed as provided in Section VIII below.

E) **Reconciliation Adjustment Date** shall be the date the Company will define an adjustment ("**Reconciliation Adjustment**") to effective rates to compensate for any over or under collection of base reate revenues during a Forward Looking Test Year. The Reconciliation Adjustment Date shall be no later than February 15 of each year. The Reconciliation Adjustment shall apply to bills rendered from April 1 to the last day of March of each year pursuant to Section VI.

F) **Final Order** as referenced in this tariff shall initially be the final order issued in Docket Number 30442. In the event there is a subsequent comprehensive rate proceeding establishing new base rates for the Company in Georgia, then the final order of the Commission in such subsequent comprehensive rate proceeding shall be the **Final Order** for purposes of administering this mechanism.

G. **New Matters** as referenced in this tariff refers to new issues, adjustments or ratemaking topics that would affect the annual GRAM filing for which there is no prior determination regarding the Company by the Georgia Public Service Commission.

IV. **Quarterly Financial Filings**

The Company shall file quarterly financial filings sixty (60) to seventy-five (75) days after the end of each quarter. The quarterly financial filings shall be in the form and contain actual data illustrated by the sample quarterly financial filing identified as Attachment I and attached to the Stipulation approved by the Commission in Docket No. 34734 by Order dated December 27, 2011. As part of the quarterly report, the Company shall provide capital budget information (in the form illustrated by the capital budget information identified as Attachment II to the Stipulation referenced above) to compare the capital budget against actual activity. Capital budget data for the Forward Looking Test Year shall be provided with a detailed description of capital expenditure items. Data for the Historic Test Year shall provide a variance analysis by providing a schedule with columns for the Historic Test Year to include capital budget categories, the amount budgeted, actual capital budget spending, and a variance between actual spending and the projected budget (as illustrated by Work Paper 6-8 of Attachment II referenced above). In the future, Staff and the Company may mutually agree in writing to modifications to the form and/or content of the quarterly financial filings without a subsequent order from the Commission, and such agreed to modifications, if any, will govern future quarterly financial filings thereafter. If Staff and the Company cannot agree on proposed modifications, the matter may be brought before the Commission for a decision.

V. **Annual GRAM Filing**

On the Annual Evaluation Date each year the Company shall file with the Commission schedules that reflect the actual annual amounts as reflected on the books and records of the Company for the Historic Test Year as well as the projected amounts expected during the Forward Looking Test Year.

A. Contents of the Annual Filing. The annual GRAM filings shall be in the form and contain actual data illustrated by the sample annual GRAM filing identified as Attachment III to the Stipulation approved by the Commission in Docket No. 34734 by Order dated December 27, 2011, and shall include:

Schedule 1: Calculation of Revenue Deficiency
Schedule 2: Average Rate Base: with supporting workpapers
Schedule 3: Income Statement
Schedule 4: Operating Revenues: with supporting workpapers
Schedule 5: Operating Expense Summary: with supporting workpapers
Schedule 6: Depreciation Expense: with supporting workpapers
Schedule 7: Taxes and Other Income: with supporting workpapers
Schedule 8: Calculation of Federal and State Income Taxes
Schedule 9: Derivation of the Income Expansion Factor
Schedule 10: Capital Structure and Cost of Capital (Projected)
Schedule 1l: Calculation of Adjustment

In the future, Staff and the Company may mutually agree in writing to modifications to the form and/or content of the annual GRAM filings without a subsequent order from the Commission, and such agreed to modifications, if any, will govern future annual GRAM filings thereafter. If Staff and the company cannot agree on modifications, then the matter shall be decided by the Commission.

B. Revenue Requirements. Regarding data that demonstrates the Forward Looking Test Year base rate revenue requirements:

a. Rate Base shall be calculated using actual net plant in service, construction work in progress, accumulated deferred income taxes, inventory, working capital, and other rate base components. Adjustments shall be reflected to incorporate forecasted capital expenditures, as well as other rate base adjustments to represent the balances during the Forward Looking Test Year. Cash Working Capital requirements will be reflected in a manner consistent with the Cash Working Capital requirements approved in the Final Order.

b. Depreciation expenses shall reflect the depreciation rates most recently approved by the Commission in the Final Order.

c. Actual Historic Test Year operating and maintenance costs (including but not limited to all payroll and compensation expense, all benefit expense, all pension expense, insurance costs, materials and supplies, bad debt costs, all medical expense, commitment and banking fees, transportation and building and lease costs) shall be adjusted to incorporate forecasted adjustments for each such operating and maintenance cost for the Forward Looking Test Year using adjustment factors that are calculated in the same manner as the adjustment factors that were used in the Final Order for:

   i. an Other Pension and Employee Benefits ("OPEB") Inflation Factor;
   ii. a Pension Account Plan Inflation Factor;
   iii. a General Inflation Factor;
   iv. a Medical Inflation Factor; and
   v. a Labor Inflation Factor.

d. The Historic Test Year data shall include actual income taxes and taxes other than income taxes, and the Forward Looking Test Year data shall include adjustments to the Historic Test Year tax data to reflect the expected taxes for the Forward Looking Test Year.

e. The Historic Test Year data shall include actual base rate revenues by billing component, and the Forward Looking Test Year data shall reflect adjustments to forecast base rate revenue billing determinants based on the base rate revenue forecasting methodologies that were used in the Final Order for projecting the number of customers and average customer use.

f. The Historic Test Year data shall include actual capital structure and cost of debt. The schedules for the Forward Looking Test Year shall reflect and be based upon the most recent 13 month average historical capital structure and cost of debt as of June 30.

g. All schedules filed pursuant to this mechanism shall reflect applicable accounting and pro forma adjustments as established in the Final Order as well as other adjustments required to account properly for atypical, unusual, or nonrecurring events.

h. Adjustment methodologies for the Pipe Replacement Program ("PRP") shall be consistent with those in the Final Order. Provided, however, that following the first Forward Looking Test Year in which no PRP costs are incurred during the relevant Historic Test Year, the PRP mechanism shall cease to operate and the costs and base rate revenues that would otherwise have been reflected in the PRP mechanism shall be included in establishing base rates under GRAM.

C. Calculation of Adjustments to Rates for the Forward Looking Test Year. The Annual GRAM filing shall include additional schedules indicating the following revenue deficiency/sufficiency calculations using the methodology accepted in the Final Order. These schedules shall identify the base rate adjustments, if any that are necessary for the Forward Looking Test Year. If adjustments are required as set forth below, the resulting Effective Rates shall also be included with the filed schedules.

a. An earnings band is established and is defined as the range between two tenths of one percent (0.2%) above and two-tenths of one percent (0.2%) below the ROE established in the Final Order. As an illustration, the ROE established in Docket 30442 was 10.7%; the earnings band range for the ROE established in Docket No. 30442 is thus 10.5% to 10.9%.

b. If the Company's earnings during the Forward Looking Test Year (excluding Reconciliation Adjustments as provided for in Section VI, if any) are projected to exceed the upper end of the

earnings band, the Annual GRAM Filing shall include an adjustment to base rates calculated to lower the base rate revenue to achieve the specified upper end of the earnings band.

c. If the Company's earnings during the Forward Looking Test Year (excluding Reconciliation Adjustments as provided for in Section VI, if any) are projected to be below the lower end of the earnings band, the Annual GRAM Filing shall include an adjustment to base rates calculated to increase the revenue in order to collect the additional base rate revenue required to achieve the specified lower end of the earnings band.

d. If the ROE is calculated to fall within the earnings band, no adjustment to base rates will occur.

D. Proof of Revenues and Rate Design. The Annual GRAM Filing shall include a schedule demonstrating the "proof of revenues" relied upon to calculate the proposed Effective Rates for the Forward Looking Test Year. The proposed base rate adjustment (if any) will be spread to each customer class' tariff customer charge and distribution charge (excluding special contracts) in proportion to the relative base rate revenue share as approved in the Final Order. The proposed new Effective Rates shall be effective on bills rendered from February 1 to January 31 (the "Rate Effective Period") unless the beginning of the Rate Effective Period is delayed as provided in Section VIII below.

VI. Calculation of the Revenue Reconciliation Adjustment

During the Rate Effective Period, generally February through January of the following year, the Company shall track actual base rate revenues collected to be compared to the projected base rate revenues as follows: By February 15th following each Rate Effective Period, the Company shall file with the Commission a Revenue Reconciliation Adjustment Filing consisting of schedules that compare (a) the preceding Forward Looking Test Year base rate revenue projections whose rates were in effect during the Rate Effective Period with (b) actual base rate revenues related to amounts billed during the Rate Effective Period for services that have been provided. These schedules shall exclude special contracts and PRP revenues. If such actual base rate revenues (excluding Reconciliation Adjustments as provided for in this Section VI, if any) during the preceding Rate Effective Period exceeded the base rate revenue projections for the Forward Looking Test Year, the Revenue Reconciliation Adjustment Filing shall include a Reconciliation Adjustment calculated to lower base rates over a 12-month period by the amount that such actual base rate revenues exceeded projections. If the Company's actual base rate revenues (excluding Reconciliation Adjustments as provided for in this Section VI, if any) during the preceding Rate Effective Period were below the base rate revenue projections for the Forward Looking Test Year, the Revenue Reconciliation Adjustment Filing shall include a Reconciliation Adjustment calculated to increase base rates over a 12-month period by the amount that such projected base rate revenues exceeded actual base rate revenues. The Reconciliation Adjustment, which relates to amounts billed during the Rate Effective Period for services that had been previously provided, will be spread to each customer class's tariff customer charge in proportion to the relative base rate revenue share as approved in the Final Order on each bill rendered from April 1 to March 31 of each year. The Company's Revenue Reconciliation Adjustment Filing will include the following information to support Staff's ability to present a recommendation on such base rate adjustments to the Commission by March 31st so that the Commission may vote on any such recommendation concerning an adjustment to base rates that will go into effect on April 1st:

a. Actual monthly base rate revenues collected;
b. Projected base rate revenues; and
c. Variance between the actual and projected base rate revenues.

VII. **Attestation**

A sworn statement shall be filed by a Company officer responsible for Georgia Operations affirming that the filed schedules are in compliance with the provisions of this mechanism and are true and correct to the best of his/her knowledge, information and belief. No testimony in addition to such attestation in support of the proposed adjustments shall be necessary at the time of the initial filing.

VIII. **Evaluation Procedures**

Because the Stipulation approved by the Commission allows only 120 days for the Staff to review the annual GRAM filing, submit a recommendation to the Commission, and for the Commission to issue an order on Staff's recommendation, the Company will endeavor to include within each Annual GRAM Filing all of the information described in this tariff provision. Within 20 days following the filing of an annual GRAM filing, if the Staff determines that the annual GRAM filing is not complete (as described in this Tariff), Staff may petition the Commission for the 120-day clock to stop until the Company provides any missing or deficient information. If no such petition is filed by Staff within the first 20 days following the annual GRAM filing, the annual GRAM filing will be deemed to be complete.

If the Commission agrees with Staff's position that an Annual GRAM filing is deficient or incomplete, the 120-day clock will be deemed to have stopped on the date that the petition is filed by Staff. The 120-day clock will begin to run again as soon as the missing information is provided or the deficiency is otherwise corrected. If the Staff issues data requests, the Company will file responses within 15 days. If the responses to the data requests are considered non-responsive by Staff, the Staff may petition for the Commission to stop the 120-day clock until responsive responses are received. If the Commission agrees with Staff's position that the data request responses are nonresponsive, the 120-day clock will be deemed to have stopped on the date that the petition is filed by Staff. The 120-day clock will begin to run again as soon as adequate responses are provided by the Company or the deficiency is otherwise corrected. In the event that the 120-day clock is stopped for any reason, the start of the Rate Effective Period (which would normally be February through January of the following calendar year) for the period in which the 120-day clock was stopped will be delayed and the Rate Effective Period will be shortened accordingly. In any event, a shortened Rate Effective Period will end at the end of January, and the next annual GRAM filing shall be made on or before October 1st so that the regular schedule as set forth herein will resume.

If the operation of the GRAM annual filing results in an adjustment to the Company's base rates as provided herein, the approved Stipulation provides that Staff shall present a recommendation on the resulting rate adjustment before the Commission by January 31st regarding any adjustment of base rates that will go into effect on February 1st.

In the event that the Staff or its representatives must incur travel expenses to the Company's offices in the course of auditing the Company's books and records to verify the quarterly financial reports, the annual GRAM filing, or any financial data provided in support of the requested adjustments, the Company shall reimburse such reasonable expenses and promptly recover the full amount of all such cost paid.

Notwithstanding the operation of this tariff provision, the Company may file a new rate case, and Staff may institute a rule nisi at anytime. The Company shall cover the costs of consulting fees reasonably incurred by Staff if the Company initiates a rate case, or if Staff initiates a rule nisi, or if Staff retains a consultant for the GRAM review process; O.C.G.A. § 46-2-33 (as such provision of law is currently

codified or as such provision may be hereinafter modified, amended, restated or re-codified) shall apply to cost incurred by the Georgia Public Service Commission to obtain reasonably necessary specialized testimony and assistance and charged to the Company as necessary costs of providing service, and the Company may promptly recover the full amount of all such costs paid by the Company.

STANDARD GAS TARIFF
FILED WITH

LOUISIANA PUBLIC SERVICE COMMISSION

ORIGINAL VOLUME NO. 1-AL

ATMOS ENERGY CORPORATION
Louisiana Gas Service Rate Division

450 Laurel Street, Suite 2100
Baton Rouge, Louisiana 70801

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RATE STABILIZATION CLAUSE
Rider RSC

A. APPLICATION

This clause is applicable to gas service under any rate schedule incorporating Rider Schedule RSC by reference. This clause will initially be in effect for a period of three years, during which period the capital structure and return on equity (ROE) shall be frozen at the levels stated herein. After the initial 3-year period, the clause will continue to operate under this same structure until either the Company or the Commission undertakes a proceeding to change the RSC mechanism, capital structure, or the ROE, and such proceeding results in a change.

B. RSC FACTORS AND ADJUSTMENT CALCULATION PROCEDURE

(1) Under this RSC, the Company shall be allowed to earn ROE of 10.40%. If the earned ROE is below or above the allowed ROE, rates will be increased or decreased by the amount necessary to increase or decrease the earned ROE to equal the allowed ROE.

(2) The Company will file an annual report showing earnings for the 12-month period ended December 31 (test year). Such filing shall be made by March 31 immediately following the close of the test year. Any appropriate rate change will become effective with the first billing cycle of July in the year following the close of the test year.

(3) The Company s annual report showing earnings shall be based on actual costs recorded in the books of the Company, and shall include any allowed adjustments as per rules stated herein. If the ROE calculated in the report is below or above the allowed ROE, the base rates under the respective rate schedules subject to RSC shall be increased or decreased for that amount necessary, in total, to restore the ROE to the allowed level. The RSC rate adjustment shall be developed using the formula described in Paragraph C.

(4) The RSC adjustment will be applied to all charges on the rate schedules to which RSC is applicable. Revised rate schedules will be filed by the Company with the Commission each time they are adjusted pursuant to the RSC and shall then become the filed rates of the Company.

RATE STABILIZATION CLAUSE
Rider RSC

C. RSC ADJUSTMENT FORMULA

(1) The RSC adjustment formula will be applied whenever the calculated return on common equity (ROE) for the test year is below or above the allowed ROE. The RSC adjustment shall be applied so as to adjust the base rates under the respective schedules to which this rider is applicable.

(2) **Step 1**
Whenever the ROE is less than 10.40%, calculate the total adjustment necessary to bring the ROE to 10.40% as follows:

$$\text{Total Adjustment} \square \frac{(.1040 \square \text{ROE}) \square (\text{CE})}{(1 - T)} \times \text{RCF}$$

Where, for the test year:

ROE	□	Return on Common Equity Capital Investment
CE	□	Common Equity Capital Investment
T	□	Combined Federal and State Income Tax Rate
RCF	□	Revenue Tax Conversion Factor

(3) **Step 1-a**
Apply first to the rate schedules a customer charge increase of up to $0.50 per month per residential bill, and proportional increases in the customer charge for other customer classes. Any remaining increase will be recovered through a uniform increase in the commodity rates of all schedules to which the RSC is applicable, in Steps 1-b and 1-c.

(4) **Step 1-b**
Allocate the total remaining adjustment, if any, among the rate schedules to which the RSC is applicable in proportion to the rate schedules□normalized gas service revenue.

(5) **Step 1-c**
For each rate schedule, divide the allocated portion of the total adjustment by the commodity charge billing units. Round the resulting increase or decrease to the nearest thousandth of a cent per CCF and apply it to all commodity charges in the rate schedule.

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RATE STABILIZATION CLAUSE
Rider RSC

(6) Step 2

Whenever the ROE is greater than 10.40%, calculate the total adjustment necessary to bring the ROE to 10.40% as follows:

$$\text{Total Adjustment} \quad \frac{(\text{ROE} - .1040) \quad (\text{CE})}{(1 - T)} \times \text{RCF}$$

Where, for the test year:

ROE		Return on Common Equity Capital Investment
CE		Common Equity Capital Investment
T		Combined Federal and State Income Tax Rate
RCF		Revenue Tax Conversion Factor

(7) Step 2-a
Any rate reduction adjustment will be achieved through a uniform decrease in the commodity rates of all schedules to which the RSC is applicable. Allocate the total adjustment among the rate schedules to which the RSC is applicable in proportion to the rate schedules normalized gas service revenue.

(8) Step 2-b
For each rate schedule, divide the allocated portion of the total adjustment by the commodity charge billing units. Round the resulting decrease to the nearest thousandth of a cent per CCF and apply it to all commodity charges in the rate schedule.

D. ANNUAL EARNINGS CALCULATIONS

(1) Rate base will include, but not be limited to, end of period plant in service, accumulated depreciation and accumulated deferred income taxes (ADIT). ADIT will be limited to rate base/ cost of service items, inclusive of ADIT associated with gains and losses on reacquired debt. Items to be included in the calculation of ADIT for inclusion in rate base are:

Environmental Activities
Directors Deferred Comp
Self Insurance Adjustment
Vacation Accrual
Worker s Comp Insurance Reserve
Customer Advances
RAR 91/93 Bond Cost Amortized
RAR 86/90 Lease Expense Amortized

RATE STABILIZATION CLAUSE
Rider RSC

Rabbi Trust True Up
SEBP Adjustment Amended Item
SEBP Adjustment
Rabbi Trust
Capitalized Selling Expense
UNICAP Section 263A Costs
Allowance for Doubtful Accounts
Clearing Account Adjustment
RAR CFWE 1990-1985
Prepaid Dues
Prepayments
Inventory Adjustment
Section 481(a) Prepayments
Pension Expense
Regulatory Asset LGS Amortization
Customer Forfeiture
Section 481(a) Cushion Gas
Section 481(a) Line Pack Gas
Amended Cost of Removal
Amended Book Amortization
Capitalized Overhead True Up
Fixed Asset Cost Adjustment
Fixed Asset Accumulation Adjustment
CWIP (see note below)
IRS Audit Adjustment Cost
IRS Audit Adjustment Accumulation
Provision Differences Cost
Other Plant
Amended Item Book Depreciation Not Reversed
Amended Item Tax Depreciation Not Claimed
ST State Net Operating Loss
ST State Bonus Depreciation
FD FAS 115 Adjustment
FD R & D Credit Valuation Allow
FD Federal Benefit on State Bonus

In addition, the amount of CWIP included in rate base in the RSC is the amount which is not eligible to receive an amount of AFUDC, as stated in section (3) below. In order to be consistent, the percentage of ineligible CWIP to total CWIP will be applied to the CWIP amount used in determining ADIT.

Additional or new book/ tax differences shall be reviewed to determine their appropriate treatment in the calculation of ADIT for Louisiana consistent with the phrase but not be limited to stated in first paragraph of this section.

RATE STABILIZATION CLAUSE
Rider RSC

To be consistent with rate base methodology, revenues will also be adjusted to reflect year-end customer levels.

Year-end balances of the reserves for injuries and damages, self insurance reserve, uncollectibles reserve and similar items for which the Company utilizes reserve accounting will be recognized as rate base additions or deductions.

(2) For the following rate base items, 13-month average of average balances will be used: materials and supplies; prepayments; and customer deposits. The balance of underground storage will be based on the average of the 12 monthly average balances. (This is derived by using a 13-month average that only gives one-half weight to the first and the last month in the test period.)

(3) Only that portion of Construction Work in Progress (CWIP) that is not eligible for AFUDC is to be included in rate base.

(4) A cash working capital allowance equal to 1/16th of non-gas O&M expense shall be included in rate base. O&M expense must be adjusted to exclude any non-cash expenses, including uncollectibles.

(5) Adjustments to test year expenses is allowed for certain items. The following are eligible for annualization at year-end levels:

(a) changes in income and franchise tax rates, the applicable items being depreciation, salaries and wages, payroll taxes and certain benefits items.

(b) employee wages based on end-of-test-year employee levels and wage rates.

(c) payroll taxes based on end-of-test-year employee levels, wage rates and payroll tax rates.

(d) pension expense based on the most recent actuarial report

(e) property and casualty insurance premiums in effect at the end of test year.

(f) depreciation expense based on end-of-test-year plant.

Annualized salaries and wages shall consider both wage rate changes and force level changes during that test year. To the extent necessary, adjustments shall be made to exclude incentive compensation expense and to reflect post retirement benefits expense other than pension on a pay-as-you-go or cash basis, consistent with Commission policy.

RATE STABILIZATION CLAUSE
Rider RSC

(6) Adjustments to normalize anomalies and out of period items will be made in order to reflect ongoing cost levels for the period in which rates will be in effect. All such adjustments will be subject to review at the time of each RSC filing.

(7) The earned ROE will be calculated using the benchmark adjusted O&M, according to the mechanism established in LPSC Docket No. U-25003. A new O&M benchmark of $39,886,000 has been established as of December 31, 2003. This benchmark will be adjusted each year for changes in the CPI-U Index, ACA Wage Index and changes in customers, according to the mechanism established in LPSC Docket No. U-25003.

(8) Changes in Atmos actual cost of debt shall be recognized in the determination of ROE. The cost of debt will be calculated to include short-term debt amounts (13-month average) and interest.

(9) Weather-normalized sales will equal the total of actual sales revenue and weather normalization adjustments in the test year. **T**

E. FILING and RESOLUTION PROCEDURES

(1) The Company will file an annual Evaluation Report showing its earnings for the test year ended December 31, on or before the following March 31. A copy of the report will be provided to the Commission Staff (Staff) at the time it is filed with the Commission. At the time each such Evaluation Report is filed, the Company will provide Staff with work papers supporting the data and calculations reflected in the Evaluation Report. Staff may request clarification and additional supporting data.

(2) Staff shall then have until the subsequent June 15, or 75 days after filing, whichever is longer, to review the Evaluation Report to ensure that it complies with the requirements of the RSC. If the Staff should detect any errors in the application of the principles and procedures of the RSC, such errors shall be communicated in writing to the Company by June 15, or 75 days after filing, whichever is longer. Each such indicated error shall include documentation of the proposed correction, to the extent possible. However, the inability to fully document a potential correction shall not serve as a basis for not considering that correction. The Company shall then have ten (10) days to review any proposed corrections, to work with the Staff to resolve any differences and to file a revised Evaluation Report reflecting all corrections upon which the Parties agree. The Company shall provide the Staff with appropriate work papers supporting any revisions made to the initial filing.

RATE STABILIZATION CLAUSE
Rider RSC

(3) Except where there is an unresolved dispute, which shall be addressed in accordance with the provisions described below, the appropriate adjustment to rates shall become effective for bills rendered on and after the first billing cycle for the month of July in the year following the close of the test year.

(4) In the event there is a dispute regarding any Evaluation Report, the Company and the Staff will work together in good faith to resolve such dispute. If the dispute is not resolved by the end of the ten (10) day period noted above, revised rates reflecting all revisions to the initially filed Evaluation Report on which the Staff and the Company agree shall become effective no earlier than July 1 as described above. Any disputed issues shall be submitted to the Commission for resolution.

(5) If the Commission s final ruling on any disputed issues requires changes in the rates initially implemented, the Company shall file a revised Evaluation Report reflecting the required changes within fifteen (15) days after receiving the Commission s order resolving the dispute. The Company shall provide a copy of the filing to the Staff together with appropriate supporting documentation. Such modified rate adjustments shall then be implemented with the next applicable monthly billing cycle.

(6) Within 60 days after receipt of the Commission s final ruling on disputed issues, the Company shall determine the amount to be refunded or surcharged to customers, if any, together with interest at the legal rate of interest. Such refund/ surcharge amount shall be applied on a percentage basis and shall be based on the customer s applicable base revenue during the period the interim rates were billed. Such refund/ surcharge amount shall be applied to customers bills in the manner prescribed by the Commission.

STANDARD GAS TARIFF
FILED WITH

LOUISIANA PUBLIC SERVICE COMMISSION

ORIGINAL VOLUME NO. 1-AT

ATMOS ENERGY CORPORATION
Trans Louisiana Gas Rate Division

450 Laurel Street, Suite 2100
Baton Rouge, Louisiana 70801

Telephone: (225) 376-4605

Contact: Christine A. Tabor

RATE STABILIZATION CLAUSE
Rider RSC

A. APPLICATION

This clause is applicable to gas service under any rate schedule incorporating Rider Schedule RSC by reference. This clause will initially be in effect for a period of three years, during which period the capital structure and return on equity (ROE) shall be frozen at the levels stated herein. After the initial 3-year period, the clause will continue to operate under this same structure until either the Company or the Commission undertakes a proceeding to change the RSC mechanism, capital structure, or the ROE, and such proceeding results in a change.

B. RSC FACTORS AND ADJUSTMENT CALCULATION PROCEDURE

(1) Under this RSC, the Company shall be allowed to earn ROE of 10.40%. A range equal to 40 basis points above and below the allowed ROE is established, such that the range between 10.00% and 10.80% ROE is hereinafter referred to as the Neutral Return Range. If earnings are below the Neutral Return Range in any test year, the Company s rates shall be adjusted upward to the bottom of the range. If earnings are above the Neutral Return Range in any test year, the Company s rates shall be adjusted downward to the top of the range.

(2) The Company will file an annual report showing earnings for the 12-month period ended September 30 (test year). Such filing shall be made by December 31 immediately following the close of the test year. Any appropriate rate change will become effective with the first billing cycle of April in the year following the close of the test year.

(3) The Company s annual report showing earnings shall be based on actual costs recorded in the books of the Company, and shall include any allowed adjustments as per rules stated herein. If the ROE calculated in the report is below or above the Neutral Return Range, the base rates under the respective rate schedules subject to RSC shall be increased or decreased for that amount necessary, in total, to restore the ROE to the Neutral Return Range. The RSC rate adjustment shall be developed using the formula described in Paragraph C.

(4) The RSC adjustment will be applied to all charges on the rate schedules to which RSC is applicable. Revised rate schedules will be filed by the Company with the Commission each time they are adjusted pursuant to the RSC and shall then become the filed rates of the Company.

RATE STABILIZATION CLAUSE
Rider RSC

C. RSC ADJUSTMENT FORMULA

(1) The RSC adjustment formula will be applied whenever the calculated return on common equity (ROE) for the test year is below the Neutral Return Range. The RSC adjustment shall be applied so as to adjust the base rates under the respective schedules to which this rider is applicable.

(2) **Step 1**
Whenever the ROE is less than 10.00%, calculate the total adjustment necessary to bring the ROE to the Neutral Return Range as follows:

$$\text{Total Adjustment} \square \frac{(.1000 \square \text{ROE}) \square (\text{CE})}{(1 - T)} \times \text{RCF}$$

Where, for the test year:

ROE	□	Return on Common Equity Capital Investment
CE	□	Common Equity Capital Investment
T	□	Combined Federal and State Income Tax Rate
RCF	□	Revenue Tax Conversion Factor

(3) **Step 1-a**
Apply first to the rate schedules a customer charge increase of up to $0.50 per month per residential bill, and proportional increases in the customer charge for other customer classes. Any remaining increase will be recovered through a uniform increase in the commodity rates of all schedules to which the RSC is applicable, in Steps 1-b and 1-c.

(4) **Step 1-b**
Allocate the total remaining adjustment, if any, among the rate schedules to which the RSC is applicable in proportion to the rate schedules□normalized gas service revenue.

(5) **Step 1-c**
For each rate schedule, divide the allocated portion of the total adjustment by the commodity charge billing units. Round the resulting increase or decrease to the nearest thousandth of a cent per CCF and apply it to all commodity charges in the rate schedule.

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RATE STABILIZATION CLAUSE
Rider RSC

(6) Step 2

Whenever the ROE is greater than 10.80%, calculate the total adjustment necessary to bring the ROE to the Neutral Return Range as follows:

$$\text{Total Adjustment} \quad \frac{(\text{ROE} - .1080) \times (\text{CE})}{(1 - T)} \times \text{RCF}$$

Where, for the test year:

ROE		Return on Common Equity Capital Investment
CE		Common Equity Capital Investment
T		Combined Federal and State Income Tax Rate
RCF		Revenue Tax Conversion Factor

(7) Step 2-a
Any rate reduction adjustment will be achieved through a uniform decrease in the commodity rates of all schedules to which the RSC is applicable. Allocate the total adjustment among the rate schedules to which the RSC is applicable in proportion to the rate schedules normalized gas service revenue.

(8) Step 2-b
For each rate schedule, divide the allocated portion of the total adjustment by the commodity charge billing units. Round the resulting decrease to the nearest thousandth of a cent per CCF and apply it to all commodity charges in the rate schedule.

D. ANNUAL EARNINGS CALCULATIONS

(1) Rate base will include, but not be limited to, end of period plant in service, accumulated depreciation and accumulated deferred income taxes (ADIT). ADIT will be limited to rate base/ cost of service items, inclusive of ADIT associated with gains and losses on reacquired debt. Items to be included in the calculation of ADIT for inclusion in rate base are:

Environmental Activities
Directors Deferred Comp
Self Insurance Adjustment
Vacation Accrual
Worker s Comp Insurance Reserve
Customer Advances
RAR 91/93 Bond Cost Amortized
RAR 86/90 Lease Expense Amortized

RATE STABILIZATION CLAUSE
Rider RSC

Rabbi Trust True Up
SEBP Adjustment Amended Item
SEBP Adjustment
Rabbi Trust
Capitalized Selling Expense
UNICAP Section 263A Costs
Allowance for Doubtful Accounts
Clearing Account Adjustment
RAR CFWE 1990-1985
Prepaid Dues
Prepayments
Inventory Adjustment
Section 481(a) Prepayments
Pension Expense
Customer Forfeiture
Section 481(a) Cushion Gas
Section 481(a) Line Pack Gas
Amended Cost of Removal
Amended Book Amortization
Capitalized Overhead True Up
Fixed Asset Cost Adjustment
Fixed Asset Accumulation Adjustment
CWIP (see note below)
IRS Audit Adjustment Cost
IRS Audit Adjustment Accumulation
Provision Differences Cost
Other Plant
Amended Item Book Depreciation Not Reversed
Amended Item Tax Depreciation Not Claimed
ST State Net Operating Loss
ST State Bonus Depreciation
FD FAS 115 Adjustment
FD R & D Credit Valuation Allow
FD Federal Benefit on State Bonus

In addition, the amount of CWIP included in rate base in the RSC is the amount which is not eligible to receive an amount of AFUDC, as stated in section (3) below. In order to be consistent, the percentage of ineligible CWIP to total CWIP will be applied to the CWIP amount used in determining ADIT.

Additional or new book/ tax differences shall be reviewed to determine their appropriate treatment in the calculation of ADIT for Louisiana consistent with the phrase but not be limited to stated in first paragraph of this section.

RATE STABILIZATION CLAUSE
Rider RSC

To be consistent with rate base methodology, revenues will also be adjusted to reflect year-end customer levels.

Year-end balances of the reserves for injuries and damages, self insurance reserve, uncollectibles reserve and similar items for which the Company utilizes reserve accounting will be recognized as rate base additions or deductions.

(2) For the following rate base items, 13-month average of average balances will be used: materials and supplies; prepayments; and customer deposits. The balance of underground storage will be based on the average of the 12 monthly average balances. (This is derived by using a 13-month average that only gives one-half weight to the first and the last month in the test period.)

(3) Only that portion of Construction Work in Progress (CWIP) that is not eligible for AFUDC is to be included in rate base.

(4) A cash working capital allowance equal to 1/16th of non-gas O&M expense shall be included in rate base. O&M expense must be adjusted to exclude any non-cash expenses, including uncollectibles.

(5) Adjustments to test year expenses is allowed for certain items. The following are eligible for annualization at year-end levels:

(a) changes in income and franchise tax rates, the applicable items being depreciation, salaries and wages, payroll taxes and certain benefits items.

(b) employee wages based on end-of-test-year employee levels and wage rates.

(c) payroll taxes based on end-of-test-year employee levels, wage rates and payroll tax rates.

(d) pension expense based on the most recent actuarial report

(e) property and casualty insurance premiums in effect at the end of test year.

(f) depreciation expense based on end-of-test-year plant.

Annualized salaries and wages shall consider both wage rate changes and force level changes during that test year. To the extent necessary, adjustments shall be made to exclude incentive compensation expense and to reflect post retirement benefits expense other than pension on a pay-as-you-go or cash basis, consistent with Commission policy.

RATE STABILIZATION CLAUSE
Rider RSC

(6) Adjustments to normalize anomalies and out of period items will be made in order to reflect ongoing cost levels for the period in which rates will be in effect. All such adjustments will be subject to review at the time of each RSC filing.

(7) Changes in Atmos actual cost of debt shall be recognized in the determination of ROE. The cost of debt will be calculated to include short-term debt amounts (13-month average) and interest.

(8) Weather-normalized sales will equal the total of actual sales revenue and weather normalization adjustments in the test year.

E. FILING and RESOLUTION PROCEDURES

(1) The Company will file an annual Evaluation Report showing its earnings for the test year ended September 30, on or before the following December 31. A copy of the report will be provided to the Commission Staff (Staff) at the time it is filed with the Commission. At the time each such Evaluation Report is filed, the Company will provide Staff with work papers supporting the data and calculations reflected in the Evaluation Report. Staff may request clarification and additional supporting data.

(2) Staff shall then have until the subsequent March 15, or 75 days after filing, whichever is longer, to review the Evaluation Report to ensure that it complies with the requirements of the RSC. If the Staff should detect any errors in the application of the principles and procedures of the RSC, such errors shall be communicated in writing to the Company by March 15, or 75 days after filing, whichever is longer. Each such indicated error shall include documentation of the proposed correction, to the extent possible. However, the inability to fully document a potential correction shall not serve as a basis for not considering that correction. The Company shall then have ten (10) days to review any proposed corrections, to work with the Staff to resolve any differences and to file a revised Evaluation Report reflecting all corrections upon which the Parties agree. The Company shall provide the Staff with appropriate work papers supporting any revisions made to the initial filing.

(3) Except where there is an unresolved dispute, which shall be addressed in accordance with the provisions described below, the appropriate adjustment to rates shall become effective for bills rendered on and after the first billing cycle for the month of April in the year following the close of the test year.

(4) In the event there is a dispute regarding any Evaluation Report, the Company and the Staff will work together in good faith to resolve such dispute. If the dispute is not resolved

RATE STABILIZATION CLAUSE
Rider RSC

by the end of the ten (10) day period noted above, revised rates reflecting all revisions to the initially filed Evaluation Report on which the Staff and the Company agree shall become effective no earlier than April 1 as described above. Any disputed issues shall be submitted to the Commission for resolution.

(5) If the Commission s final ruling on any disputed issues requires changes in the rates initially implemented, the Company shall file a revised Evaluation Report reflecting the required changes within fifteen (15) days after receiving the Commission s order resolving the dispute. The Company shall provide a copy of the filing to the Staff together with appropriate supporting documentation. Such modified rate adjustments shall then be implemented with the next applicable monthly billing cycle.

(6) Within 60 days after receipt of the Commission s final ruling on disputed issues, the Company shall determine the amount to be refunded or surcharged to customers, if any, together with interest at the legal rate of interest. Such refund/ surcharge amount shall be applied on a percentage basis and shall be based on the customer s applicable base revenue during the period the interim rates were billed. Such refund/ surcharge amount shall be applied to customers bills in the manner prescribed by the Commission.

RIDER SCHEDULE 327
STABLE / RATE ADJUSTMENT RIDER

APPLICABILITY

Stable/Rate is applicable to all Company rate schedules except Rate Schedule 319 (Flex Rate), Rate Schedule 323 (Spot Gas Sales and/or Transportation) and Rate Schedule 325 (Municipal Gas Distributors). Stable/Rate is not applicable to special contracts with manufacturers specifically approved by the Commission under MCA §77-3-35(1). To the extent that any provision in this plan may conflict with applicable statutes, said statutes shall be controlling.

EXPLANATION

Immediately following the end of each Annual Period during the operation of this tariff, a determination is made in accordance with this tariff as to whether or not the Company's jurisdictional revenues should be increased, decreased, or remain the same. If it is determined that jurisdictional revenues should be increased or decreased, billings under the above referenced rate schedules are adjusted in the manner and for the time period provided. This adjustment is added to or subtracted from the billings rendered under other rate schedules then in effect and the revised billings constitute the rates in effect until changed as provided by this tariff or as otherwise provided by law. The determination of whether to change revenues and, if so, the calculation of the Stable/Rate adjustment is made for each Annual Period as follows:

(1) Determine Company's Expected Return which is expressed as a percentage return on Rate Base Equity.

(2) Annually determine the Benchmark Return on Rate Base Equity.

(3) Annually determine the Company's current Performance Adjuster.

(4) Add or subtract the Company's Performance Adjuster to or from the Benchmark Return to establish the Company's Performance Based Benchmark Return.

(5) Compare Company's Expected Return to the Company's Performance Based Benchmark Return to determine whether revenues should be increased, decreased, or remain the same.

(6) If the Expected Return is either higher or lower than the Performance Based Benchmark Return by more than 100 basis points, then the revenue increase or decrease necessary to achieve the Performance Based Benchmark Return is calculated in accord with Appendix "C". If the difference between Expected Return and the Performance Based Benchmark Return is 100 basis points or less, it is within the Allowed Return and no change in revenues is deemed necessary.

(7) If it is determined that a change in revenues should be made, then a change shall be made as follows:

(a) If, for the twelve month period ended June 30, the Company's Expected Return as defined below, is greater than 100 basis points below the Performance Based Benchmark Return as defined below, the Stable/Rate Adjustment factor shall be increased by the amount necessary to make the Expected Return equal to the Performance Based Benchmark Return less 25 basis points.

(b) If, for the twelve month period ended June 30, the Company's Expected Return as defined below, is greater than 100 basis points above the Performance Based Benchmark Return as defined below, then the Stable/Rate Adjustment Factor shall be decreased by the amount necessary to make the Expected Return equal to the Performance Based Benchmark Return plus 25 basis points.

RIDER SCHEDULE 327
STABLE / RATE ADJUSTMENT RIDER

DEFINITIONS

(1) "Expected Return" is defined as Net Income divided by average Rate Base Equity expressed as a percentage return on Rate Base Equity and calculated in accordance with Appendix "A".

(2) "Net Income" is defined as Revenues less Expenses, all as more fully set forth in Appendix "A".

(3) "Revenues" are defined as those Test Year jurisdictional revenues specified in Appendix "A" and adjusted for Known and Measurable Changes.

(4) "Expenses" are defined as those jurisdictional Test Year expenses, including allocated expenses, specified in Appendix "A" and adjusted for Known and Measurable Changes.

(5) "Rate Base Equity" is defined as a sum equal to Company's total Rate Base times the percentage of Company's total capitalization attributable to equity capital as more fully set forth in Appendix "A".

(6) "Rate Base" is defined as the average of the expected rate base at the beginning and the end of the Rate Period. Projections of Rate Base are limited to the following: plant-in-service, accumulated depreciation and accumulated deferred income tax. All other rate base balances are based on the historic test period, with the beginning rate period and ending rate period amounts being the same as the per book evaluation amount. Projection of future increases in plant in service shall be based on Board approved capital expenditure budget numbers only and on reasonable numbers for October agreed upon by the parties on an ad hoc basis. Any items included in the Company budget as contingent shall be evaluated by the Company at the evaluation date and excluded if expenditure during the budget period is unlikely. The calculation of Rate Base shall be adjusted up or down to account for any prior errors in calculation. These calculations shall be made in accordance with and in the manner set forth in Appendix "A".

(7) "Benchmark Return" is defined as the number calculated in accordance with Appendix "B".

(8) "Performance Based Benchmark Return" or "PBBR" is defined as Benchmark Return plus or minus Company's current Performance Adjuster.

(9) "Allowed Return" is defined as a range of 100 basis points above and 100 basis points below the Performance based Benchmark Return. Expected Returns within the Allowed Range shall not cause any adjustment in revenues.

(10) "Performance Adjuster" or "PA" is defined as the number calculated in accordance with Appendix "E".

RIDER SCHEDULE 327
STABLE / RATE ADJUSTMENT RIDER

DEFINITIONS-continued

(11) "Known and Measurable Changes" in revenues are defined as changes which: a) will accrue as a result of prior rate changes or prior Stable/Rate adjustments, b) will accrue as a result of normal weather, or (c) are attributable to industrial or large commercial customer load which is known to be lost or added as of the Annual Evaluation Date. In regard to expense, "Known and Measurable Changes", shall mean changes in non-managerial and non-executive wage and benefit levels, tax rates and assessments, postage rates, or levels of other items of expense (a) in effect as of the Annual Evaluation Date and (b) established by contract or government action as of the Annual Evaluation Date and which will occur at some time during the Rate Period. The calculation of depreciation expense shall be based on plant account balances at the end of the Test Year.

(12) "Annual Evaluation Date" shall be September 5 each year.

(13) "Test Year" is defined as the 12-month period ending as of the last day of June of each year.

(14) "Rate Period" is defined as the 12-month period in which a given rate adjustment is to be effective. A Rate Period begins November 1 of each year.

(15) "Company" is defined as the Mississippi business unit operations of Atmos Energy Corporation and that portion of Atmos Energy Corporation's assets, liabilities, expenses, revenues and capital properly allocated to such operations.

EVALUATION PROCEDURES

On or before each Annual Evaluation Date, Company will submit a sworn evaluation with supporting work papers including a calculation of Expected Return, Allowed Return, a calculation of any revenue adjustment needed, and any proposed revision to the Stable/Rate adjustment factor. With each annual filing, Company shall provide complete documentation supporting each item in Appendix "A" and "B". If (1) the Public Utilities Staff ("Staff") disputes whether the calculation of any needed adjustment has been made strictly in accord with the provisions of this Tariff or (2) the Staff believes some item of expense or revenue was improperly recorded to an account or is imprudent in amount or purpose, then, in such event, the Staff may request clarification and additional data, and the Company will provide the same. Staff shall notify the Company in writing and with particularity setting forth the basis for such dispute and the adjustment or amount that Staff believes to be correct. Such notification shall occur on or before the end of the October following the end of the Test Year. This notification shall also notify of any rejected revisions to originally filed numbers. The Staff and the Company shall work in good faith to resolve any disputes by written stipulation. If the Company and the Staff are not able to resolve a disputed matter by agreement prior to the end of the November following the end of the Test Year, then, in such event, the Company and Staff shall jointly submit to the Commission a statement of the issues to be resolved. The Company and Staff may submit separate memoranda supporting their respective positions. The Commission shall resolve the matter by written order on or before the end of the January following the end of the Test Year.

RIDER SCHEDULE 327
STABLE / RATE ADJUSTMENT RIDER

EVALUATION PROCEDURES-continued

Items that are disputed by Staff as described above and which are unresolved by agreement on or before the end of the October following the end of the Test Year are not put into effect. All portions of the adjustment as calculated by the Company that are undisputed as of the last day of the October following the end of the Test Year are put into effect. An appropriate adjustment to rates is made (including an adjustment for the time value of money at the Company's current total cost of capital) to collect for Company's benefit or to refund to the benefit of Company's customers any over or under charge associated with a disputed item that was erroneously not placed into effect or which was erroneously placed into effect as determined by subsequent Commission order.

HEARINGS

Each annual revenue adjustment is separately considered for the purpose of determining whether a hearing is required pursuant to Mississippi Code Annotated § 77-3-39(1) (Supp. 1997), and no such hearing is required if the amount of any separate annual adjustment to the level of jurisdictional revenues of the utility is not a "major change" as defined in Mississippi Code § 77-3-37(8) (Supp. 1997). A hearing is required as provided in Mississippi Code Annotated § 77-3-2(3)(c)(ii) (Supp. 1997), if the cumulative change in any calendar year exceeds the greater of Two Hundred Thousand Dollars ($200,000) or four percent (4%) of the annual revenues of the utility.

The effective date of any adjustment is the date of the first billing cycle for the month in which any such adjustment is to be made as set forth in the Evaluation Procedures described above.

TERM

This tariff shall be effective upon approval by the Mississippi Public Service Commission. The first evaluation shall be made on the first Annual Evaluation Date after the tariff becomes effective. Nothing herein shall prevent the Company or Staff from proposing, in the manner provided by law, changes in or abandonment of this tariff at any time but this tariff shall continue in effect until modified or terminated as provided by MCA § 77-3-41 (Supp. 1997).

MAJOR MODIFICATIONS AND FORCE MAJEURE PROVISIONS

It is recognized that Company must from time to time construct or acquire major plant, make major modifications to existing plant, or comply with environmental laws and regulations. The addition or modification of such plant may significantly increase the Company's revenue requirements and require a significant rate adjustment. This tariff is not designed to handle any rate increase occasioned by such major addition or modification of plant. Should the Company construct, have constructed, or purchase in place major modifications to existing plants, the Company may file for rate or other relief outside this tariff, but in accordance with the law of the State of Mississippi governing such filings, and the request shall be handled by the Commission in this regular manner.

RIDER SCHEDULE 327
STABLE / RATE ADJUSTMENT RIDER

MAJOR MODIFICATIONS AND FORCE MAJEURE PROVISIONS- continued

If any cause beyond the reasonable control of the Company, such as natural disaster, damage or loss of capacity, orders or acts of civil or military authority, the happening of any event or events which cause increased cost to the Company, or other causes whether similar or not, results in a deficiency in revenues which is not readily capable of being redressed in a timely manner under this tariff, the Company may file for rate or other relief outside this tariff, but in strict accord with the law of the State of Mississippi governing such filings and the said request shall be handled by the Commission in its regular manner.

RATE DESIGN

Experimental, developmental, and alternative rate schedules are appropriate tools for the Company to use to meet the requirements of the changing business environment and the increasing competition being experienced by the Company and throughout the natural gas industry. Therefore, nothing in this tariff shall be interpreted as preventing the Company from revising, adopting, or implementing rate schedules as may be appropriate and as provided by law. Any such schedules shall be filed with the Commission in accordance with the procedures then in effect during the term of this tariff.

ADJUSTMENT CLAUSES

The Company's PGA and WNA Riders are not to be affected by this tariff in any manner. The revenues received by the Company as a result of such clauses are included in the Company's revenues to determine the Company's Expected Return. However, revenue changes as a result of the PGA or WNA riders are not included for purposes of the limitations expressed in the Hearings section above.

CHARITABLE CONTRIBUTIONS AND ADVERTISING EXPENSES

The Company reports to the Commission the name of the recipient of each charitable contribution made by the Company and which is included in the Stable/Rate calculation together with the amount of such contribution. Additionally, Company reports the total of its recoverable and non-recoverable advertising expenses. The Company's report of charitable contributions and advertising expenses is made annually in the format set forth in Appendix "D" and as part of its Annual Stable/Rate Evaluation.

RIDER SCHEDULE 327
STABLE / RATE ADJUSTMENT RIDER

(1)	(2)	(3)	(4)	(5)	(6)
LINE #	RATE BASE	PER BOOK EVALUATION __/__/__	BEGINNING PERIOD	ENDING PERIOD	SOURCE
1.	PLANT-IN-SERVICE				FERC ACCTS. 101,102,106
2.	GAS PLANT HELD FOR FUTURE USE				FERC ACCT. 105
3.	GAS PLANT ACQUISITION ADJ.				FERC ACCT. 114****
4.	NON-CURRENT GAS STORED				FERC ACCT. 117
5.	CONST. WORK-IN-PROGRESS				FERC ACCT. 107*
6.	LESS: DEPRECIATION	_____	_____	_____	FERC ACCTS. 108; 111; 115****
7.	NET PLANT	_____	_____	_____	LINES 1, 2, 3, 4 & 5 LESS LINE 6
	PLUS:				
8.	WORKING CAPITAL	_____	_____	_____	12.5% OF OPER. EXP.**
8A	WATER HEATER PROGRAM FINANCING NET OF RESERVES	_____	_____	_____	FROM FERC ACCT. 142 SUB-ACCT. 11104
	INVENTORY:				
9.	MATERIAL & SUPPLIES				FERC ACCT. 154
10.	GAS STORED UNDERGROUND	_____	_____	_____	FERC ACCT. 164.1***
11.	TOTAL INVENTORY	_____	_____	_____	SUM OF LINES 9 & 10
12.	PREPAYMENTS	_____	_____	_____	FERC ACCT. 165
	LESS:				
13.	DEFERRED INCOME TAX*****				FERC ACCTS 281-283 NET OF ACCT 190
14.	CUSTOMER ADVANCES FOR CONST.				FERC ACCT. 252
15.	BAD DEBT				RESERVE FERC ACCT 144
15A.	INJURY AND DAMAGE RESERVE				FERC ACCT 228.2
15B.	VACATION ACCRUALS				FROM FERC ACCT 232.0 SUB-ACCT.21049
15C.	R AND D SURCHARGE FUND				FROM FERC ACCT 228.4 SUB-ACCT.28109
16.	UNFUNDED POST-RETIREMENT BENEFITS				FROM FERC ACCTS. 242 & 253
17.	UNFUNDED PENSION LIABILITY (SFAS 87)				FROM FERC ACCTS 186 & 253
		_____	_____	_____	
18.	RATE BASE	_____	_____	_____	LINES 7, 8,8A, 11, 12, LESS LINES 13-17
19.	AVERAGE RATE BASE FOR PERIOD			_____	(LINE 18 (COL. 4 PLUS COL. 5))DIVIDED BY 2
20.	ADJUSTMENT FOR PRIOR ESTIMATION ERROR			_____	APPENDIX "A", PAGE 3 LINE 7
21.	ADJUSTED RATE BASE			_____	LINE 19 PLUS LINE 20

APPENDIX "A"
Page 1
CALCULATION OF EXPECTED RETURN

RIDER SCHEDULE 327
STABLE / RATE ADJUSTMENT RIDER

Footnote applicable to APPENDIX "A" Page 1: Projections of Rate Base are limited to the following: plant-in-service, accumulated depreciation and accumulated deferred income tax. All other rate base balances are based on the historic test period, with the beginning rate period and ending rate period amounts being the same as the per book evaluation amount.

*Less than one year in duration, only.
**See Page 2 of this Appendix.
***This value is an average of the past 12 months.
****Excludes amounts arising from Yazoo Investments merger.
*****Deferred Income Taxes will include only those taxes which are associated with an item actually included in rate base. The deferred income taxes will be calculated in a manner consistent with the tax accounting methods, elections and positions utilized by the Company in preparing its income tax filings. Deferred income taxes reflected in rate base will be sufficient so as to prevent the Company from violating the normalization provisions of the Internal Revenue Code.

APPENDIX "A"
Page 1A
CALCULATION OF EXPECTED RETURN

RIDER SCHEDULE 327
STABLE / RATE ADJUSTMENT RIDER

LINE #	(1) WORKING CAPITAL	(2) PER BOOK TEST YEAR	(3) ADJUSTMENTS (A)	(4) ADJUSTED TEST YEAR	(5) SOURCE
A.	OPERATING AND MAINTENANCE EXPENSE				FERC ACCTS. 401 & 402, EXCEPT FERC O&M DETAIL 800-813, 858, AND 881
B.	RENT OF DIST. PROPERTY				FERC ACCT. 401-881
C.	GENERAL TAXES				FERC ACCT. 408.1
D.	MISC. INCOME DEDUCTIONS	_____	_____	_____	FERC ACCTS. 426.1
E.	TOTAL OPERATING EXP.				SUM OF LINE A-D
F.	NON-RECOVERABLE LOBBYING EXP.	_____	_____	_____	LOBBYING EXPENSE RECORDED IN O&M
G.	ALLOWABLE O. & M.				LINE E LESS LINE F
	TIME 1/8 ALLOWANCE	_____	_____	_____	
H.	ALLOWED WORKING CAPITAL	_____	_____	_____	LINE G TIMES 12.5%

Note:
(A) Adjustments only for "known and measurable changes" as defined in the definitions section.

APPENDIX "A"
Page 2
CALCULATION OF EXPECTED RETURN

RIDER SCHEDULE 327
STABLE / RATE ADJUSTMENT RIDER

ADJUSTMENT TO RATE BASE CALCULATION
For Prior Estimation Error For Period Ended Twelve Months Prior
To Beginning of Rate Period - Current Evaluation

(1)	(2)	(3)	(4)	(5)	(6)
LINE #	ITEMS	ACTUAL BEGINNING RATE PERIOD	ACTUAL ENDING RATE PERIOD		SOURCE
1.	PLANT-IN-SERVICE				FERC ACCTS. 101, 102, 106
2.	LESS: DEPRECIATION				FERC ACCTS. 108; 111; 115
3.	DEFERRED INCOME TAX				FERC ACCTS 281-283 NET OF ACCT 190 (see footnote APPENDIX A - Page 1A)
4.					LINE 1 LESS LINES 2 AND 3
5.	ACTUAL AVERAGE PLANT LESS ACCUM DEPREC & LESS DEFERRED INCOME TAX				LINE 4 (COL 3 PLUS COL 4) DIVIDED BY 2
6.	AVG PLANT, A/D & DEF INC TAX PROJECTED IN THE STABLE/RATE EVALUATION MADE TWO FILINGS PRIOR TO THE CURRENT FILING				EVALUATION 2 YRS PRIOR, APPENDIX A - Page 1, THE AVERAGE PROJECTIONS ON LINES 1, 6 & 13
7.	RATE BASE ADJUSTMENT TO CURRENT EVALUATION				LINE 5 LESS LINE 6

APPENDIX "A"
Page 3
CALCULATION OF EXPECTED RETURN

THIS PAGE IS NO

LONGER BEING USED.

APPENDIX "A"
Page 4
CALCULATION OF EXPECTED RETURN

RIDER SCHEDULE 327
STABLE / RATE ADJUSTMENT RIDER

(1) LINE #	(2) EXPECTED EQUITY RETURN ON RATE BASE	(3) TEST YEAR	(4) ADJUSTMENTS (A)	(5) ADJUSTED TEST YEAR	(6) SOURCE
1.	OPERATING REVENUE				FERC ACCT. 400
2.	LESS GAS PURCHASED FOR RESALE	_____	_____	_____	FERC ACCTS. 401-800 THROUGH 401-813, AND 401-858
3.	MARGIN	_____	_____	_____	LINE 1 LESS LINE 2
	LESS:				
4.	OPERATING AND MAINTENANCE EXPENSE				FERC ACCTS. 401 & 402, EXCEPT FERC O&M DETAIL 800-813, 858 AND 881
5.	RENT OF DIST. PROPERTY				FERC ACCT. 401-881
6.	GENERAL TAXES				FERC ACCT. 408.1
7.	MISC. INCOME DEDUCTIONS				FERC ACCT. 426.1
8.	DEPRECIATION				FERC ACCT. 403 & 404
9.	AMORT. OF GAS INVESTMENT				FERC ACCT. 405
10.	AMORT. OF DEBT EXPENSE				FERC ACCT. 428 & 428.1 (ALLOC FROM CONSOL)
11.	ALLOW. FOR FUNDS USED DURING CONST.				FERC ACCT. 432
11A.	AMORT. OF INV. TAX CREDIT	_____	_____	_____	FERC ACCT. 411.4
12.	TOTAL OPER. REV. DEDUCTIONS	_____	_____	_____	SUM OF LINES 4-11
13.	NET OPERATING REVENUE	_____	_____	_____	LINE 3 LESS LINE 12
14.	INTEREST ON LONG-TERM DEBT			LINE 1)	(SEE APPENDIX "A", PAGE 7,
15.	INTEREST ON CUSTOMER DEP.			_____ LINE 2)	(SEE APPENDIX "A", PAGE 7,
16.	TOTAL DEBT EXPENSE			_____	SUM OF LINES 14 & 15
17.	FUNDS AVAIL. FOR INC. TAX AND EQUITY				LINE 13 LESS LINE 16
18.	LESS TAXES:			_____	EFFECTIVE TAX RATE TIMES LINE 17
19.	ADJ. INCOME AVAILABLE FOR EQUITY	_____	_____	_____	LINE 17 LESS LINE 18
20.	RETURN ON EQUITY RATE BASE	_____	N/A _____	RATE BASE FROM LINE 4, PAGE 7 OF APPENDIX "A"	LINE 19 DIVIDED BY EQUITY

Note:
(A) Adjustments only for "known and measurable changes" as defined in the definitions section.

APPENDIX "A"
Page 5
CALCULATION OF EXPECTED RETURN

RIDER SCHEDULE 327
STABLE / RATE ADJUSTMENT RIDER

DETAIL OF KNOWN AND MEASURABLE CHANGES:

A. ANNUALIZED PRIOR ADJUSTMENTS		EXPLANATION
1. ADJUSTABLE ANNUAL REVENUE FROM THE TEST PERIOD	$XXXXX	FROM APPENDIX C PAGE 3, COL 3.
2. MOST RECENT AUTHORIZED STABLE RATE FACTOR MINUS 1	.XXXXX	FROM COMMISSION ORDER.
3. ANNUALIZED STABLE RATE REVENUE FROM MOST RECENT EVALUATION	XXXXXX	LINE 1 TIMES LINE 2(THIS IS THE AMT OF STABLE RATE REVENUE THAT WOULD HAVE BEEN COLLECTED IF THE MOST RECENT FACTOR HAD BEEN IN PLACE THE ENTIRE TEST YR).
LESS:		
4. ACTUAL STABLE RATE REV COLLECTED IN THE TEST PERIOD	XXXXXX	FROM APPENDIX C PAGE 3, COL 1.
5. ADJ. TO ANNUALIZE REVENUE FROM MOST RECENT STABLE RATE FACTOR	XXXXXX	LINE 3 LESS LINE 4.
LESS:		
6. MUNICIPAL FRANCHISE TAX	XXXXXX	LINE 5 TIMES AVG MUNIC FRANCHISE TAX RATE, APPENDIX C PAGE 2.
7. ANNUALIZED PRIOR ADJUSTMENT	$XXXXXX	LINE 5 LESS LINE 6 (ADJ. ON LINE 7 CARRIES FORWARD TO PAGE 6B, 1A).

B. OTHER KNOWN AND MEASURABLE CHANGES

_____
_____
_____

RIDER SCHEDULE 327
STABLE / RATE ADJUSTMENT RIDER

LINE #	TYPE OF CAPITAL	PERCENTAGE OF CAPITAL	CAPITAL ALLOCATED/ RATE BASE	ACTUAL INTEREST RATE & EQUITY RET.	DEBT* & EQUITY COST
1.	LONG TERM DEBT	0.000%	0	0.00%	0
2.	CUSTOMER DEPOSITS	0.000%	0	0.00%	0
3.	TOTAL DEBT	0.000%			
4.	COMMON EQUITY**	0.000%	0	(PBBR)	0
5.	TOTAL EQUITY	0.000%			
6.	TOTAL CAPITALIZATION	0.000%			

Long term debt is accounts 181, 189, and 221 through 226 (sub-accounts related to zero interest notes if applicable).

Customer deposits is account 235.

Common equity is accounts 201 through 217, (excludes Yazoo Investment merger adjustment).

Percent of Capital balances are determined as of the end of the Test Period.

The Customer Deposit percentage of capital shall be equal to the ratio of Mississippi Customer Deposits to Rate Base. The Long Term Debt and Equity percentages shall be based on the Company's consolidated capital amounts.

*Derived by actual interest rate and equity return times allocated rate base.
**Excludes amounts arising from Yazoo Investment merger.

RIDER SCHEDULE 327
STABLE / RATE ADJUSTMENT RIDER

CALCULATION OF BENCHMARK RETURN ON RATE BASE EQUITY

The Company's initial Benchmark Return on Rate Base Equity is 10.80%. Benchmark Return is recalculated in connection with the Company's annual evaluation.

To calculate Benchmark Return each year, the results from the following two methodologies are averaged:

I. Discount Cash Flow (DCF)
II. Regression Analysis

Notwithstanding any other provision to the contrary, the data utilized in the annual recalculation of Benchmark is data that is no more recent than June of the year in which the recalculation is made.

Discounted Cash Flow

The following annual version of the DCF model is used.

$$k = \frac{D_1}{P_o} + g$$

Where:

k = Cost of common equity for each gas utility.

D_1 = The dividend for the next annual period as calculated as Utility's dividend for the current year As determined from The Value Line Investment Survey at June 30 times (one plus (g)).

P_o = Stock price for the gas utility. The stock price used in the formula shall be the average of the weekly closing stock prices for April through June as published by Yahoo.

g = Growth rate for the gas utility. The average of the projected earnings growth rates for the gas utility reported by First Call (I/B/E/S 5-year median) and Zack's (120 day mean/consensus estimate) and the Value Line Investment Survey.

The DCF model shall be applied to a group of gas utilities derived from the companies contained in the Natural Gas (Distribution) Industry group in the Value Line Investment Survey. The gas companies included in the group shall be those with annual operating revenues not less than one-half nor more than twice those of Atmos Energy Corporation. In the event that the aforementioned selection criteria results in fewer than 10 sample companies, such group shall be represented by the ten companies in The Value Line Investment Survey list having the closest annual revenues to Atmos Energy Corporation. Provided, however, that no company shall be included in the group if the required information concerning the company is not available or if the dividend growth rate is zero or a negative number, or it does not pay a cash dividend.

RIDER SCHEDULE 327
STABLE / RATE ADJUSTMENT RIDER

The DCF model described above shall be performed for each comparable utility. The truncated mean, derived by discarding the highest and the lowest results of the DCF calculations for the group, shall be used as the DCF cost of equity.

Regression Analysis

The regression analysis shall be estimated via ordinary least squares (OLS) regression with an adjustment for serial correlation. The serial correlation adjustment shall be the Prais-Winsten technique. If the Rho coefficient is found to be statistically significant at the 0.10 level, then the adjusted equation shall be used. If serial correlation is not detected, then the unadjusted equation shall be used.

Y □ a □ b (Bond) □ c (Dummy)

The model shall use data for the period 1982 to the present. The dependent variable, Y, is the average return on common equity allowed in all gas cases by state (sometimes local) regulatory commissions as reported as reported by Regulatory Research Associates for a given calendar year. The independent variable, b (Bond), is Moody's average annual A-rated public utility bond seasoned yields for a given calendar year. The independent variable, c (Dummy), is a dummy variable to take account of unusual fluctuations in Y and b (Bond) at the beginning of the period of analysis. C (Dummy) takes on the value of one for the years 1982 □ 1986 and zero for the remaining years. Parameters, a and b, from the estimated equation along with the monthly Moody□s A-rated utility bond yields for the most recent calendar quarter are used to solve the equation and calculate the projected Y for the Company. Parameter c does not enter the final calculation, since Dummy is zero for all years after 1986. If Rho is present, it does not enter the calculation either.

The most current version of the LIMDEP model will be used to estimate the equation.

Flotation Costs

Flotation Costs of 12.5 basis points shall be added to the average of the DCF and Regression Analysis calculations as an adjustment for issuance costs.

RIDER SCHEDULE 327
STABLE / RATE ADJUSTMENT RIDER

LINE #	DETERMINATION OF REVENUE ADJUSTMENT	SOURCE
A.	EXPECTED RETURN ON EQUITY (AFTER ADJ.)	APPENDIX A, PAGE 5, LINE 20, COL. 5
B.	PERFORMANCE BASED BENCHMARK RETURN	APPENDIX B AND APPENDIX E
C.	DIFFERENCE PBBR/ER	LINE A LESS LINE B
D.	ALLOWED DIFFERENCE PBBR/ER	PAGE 1, ITEMS 6 AND 7 OF RIDER SCHEDULE
E.	ALLOWED ADJUSTMENT TO RATES	EQUALS LINE D
F.	RATE BASE--EQUITY PORTION	FROM APPENDIX A, PAGE 7, LINE 4
G.	CHANGE IN EQUITY REV. FOR REQ. RET.	LINE E TIMES F
H.	TAX EXPANSION	LINE G DIVIDED BY TAX EXPANSION LESS LINE G (SEE PAGE 2, APPENDIX "C")
I.	TOTAL REVENUE CHANGE REQUIRED	LINE G PLUS LINE H

LINE #	FOUR PERCENT TEST	SOURCE
J.	ACTUAL GROSS REV. FROM TEST PERIOD	ACCTS. 4800-4950 TRIAL BAL.
K.	FOUR PERCENT OF GROSS REVENUE	LINE J TIMES 4%
L.	NET ADJUSTMENT ALLOWED	LINE I OR LINE K, WHICHEVER IS LESS

APPENDIX "C"
Page 1
CALCULATION OF REVENUE ADJUSTMENT

RIDER SCHEDULE 327
STABLE / RATE ADJUSTMENT RIDER

TAX EXPANSION FACTOR

LINE #		
1	GROSS REQUIREMENT	1.0000
2	MUNICIPAL FRANCHISE TAX	- 0.0166
3	LINE 1-2	0.9834
4		
5	STATE INCOME TAX [5% X Line 3]	- 0.0492
6	LINE 3-5	0.9342
7		
8	FEDERAL INCOME TAX [35% X LINE 6]	- 0.3272
9	LINE 6-8	0.6070
10		
11	EXPANSION FACTOR	0.6070

NOTE: TAX RATES SUBJECT TO CHANGE. EFFECTIVE MUNICIPAL FRANCHISE TAX RATE RECALCULATED EACH EVALUATION.

APPENDIX "C"
Page 2
CALCULATION OF REVENUE ADJUSTMENT

RIDER SCHEDULE 327
STABLE / RATE ADJUSTMENT RIDER

DETERMINATION OF FACTOR APPLIED TO RATES
TO ACHIEVE REQUIRED REVENUE CHANGE

CALCULATION OF TEST PERIOD REVENUE

	(1) ACTUAL COLLECTION	(2) EFFECTIVE RATE	(3) ADJUSTABLE REVENUE	EXPLANATION
1. Jul				LINE 1 THROUGH LINE 12:
2. Aug				COLUMN 1 CONTAINS THE
3. Sep				ACTUAL STABLE/RATE
4. Oct				COLLECTION FOR EACH MONTH
5. Nov				IN THE TEST PERIOD AS
6. Dec				OBTAINED FROM COMPANY
7. Jan				REVENUE REPORTS PROVIDED
8. Feb				STAFF.
9. Mar				COLUMN 2 CONTAINS THE
10. Apr				EFFECTIVE STABLE/RATE FACTOR
11. May				FOR EACH MONTH LESS 1.
12. Jun				COLUMN 3 IS DETERMINED BY DIVIDING COL 1 BY COL 2.
13. Total				SUM OF LINES 1 THROUGH 12.
14. Current Net Adjustment Allowed				FROM APP.C,PAGE 1,LINE L.
15. Annualized Stable Rate Revenue from most recent Evaluation				FROM APP.A,PAGE 6,LINE 3.
16. Net Annual Change to Base Revenue				LINE 14 + LINE 15.
17. Rate Adjustment Factor				ONE + (LINE 16 DIVIDED BY LINE 13 COL 3).

THE RATE ADJUSTMENT FACTOR WILL BE APPLIED TO THE ADJUSTABLE RATE REVENUE IN THE NEXT RATE PERIOD.

APPENDIX "C"
Page 3
CALCULATION OF REVENUE ADJUSTMENT

RIDER SCHEDULE 327
STABLE / RATE ADJUSTMENT RIDER

TO BE FILED WITH EACH ANNUAL EVALUATION.

Charitable Contributions 7/1/___ to 6/30/___

Account Nos. _____

RECIPIENT	AMOUNT
(Detail)	

Advertising Expenses 7/1/___ to 6/30/___

RECOVERABLE	NON-RECOVERABLE
Account Nos._____	Account Nos._____
(Detail)	

APPENDIX "D"
Page 1
CHARITABLE AND ADVERTISING EXPENSES

RIDER SCHEDULE 327
STABLE / RATE ADJUSTMENT RIDER

PERFORMANCE ADJUSTER

The following performance indicators are used to measure the operational performance of the Company and to determine the Company's Performance Adjuster. The Company's Performance Adjuster is determined annually in conjunction with the Company's annual evaluation. Based on the Company's performance, a score of 0 to 10 on each indicator is determined, the scores are weighted as provided herein, and the overall score is rounded to the nearest tenth (.05 and greater being rounded to .1). This performance score is then multiplied by .001 and .005 is subtracted from the resulting number to determine the Performance Adjuster which may be a positive or negative number. This Performance Adjuster is then added to the Benchmark Return to calculate the Company's Performance Based Benchmark Return. The Performance Adjuster falls between a positive and a negative 50 basis points.

If for any reason beyond the reasonable control of the Company, an indicator's score cannot be calculated and no provision is made in the indicator or by agreement between Company and Staff, the last available score is used.

I. Customer Price

A. General Description

The Customer Price Indicator compares the average price per delivered Mcf paid by Company's residential customers against the average price paid to a group of comparable gas local distribution companies. This indicator measures how the Company's firm residential rates compare with other gas utilities in the same general geographic area.

B. Formula and Data Source:

For each comparison company, the comparison company's most recent EIA 176 ("Supply and Disposition of Natural Gas") Report filed with the United States Department of Energy, Energy Information Administration, is the source of the data used to calculate the average price. The indicator is calculated by comparing the weighted average price paid by the firm residential customers of the comparison companies to the weighted average price paid by the firm residential customers of Atmos Energy Mississippi. The comparison companies are: all gas distribution companies located in the states of Mississippi, Alabama, Louisiana, Florida, Tennessee, Arkansas and Georgia who file such reports indicating at least one BCF of annual sales to residential customers.

C. Scale:

The Company's score on this performance indicator is measured by dividing Company's weighted average price by the weighted average price of the comparison companies and scoring the results as follows:

Customer Price Indicator (%)			Scale
114%	-	above	0
111%	-	113%	1
108%	-	110%	2
105%	-	107%	3
102%	-	104%	4
99%	-	101%	5
96%	-	98%	6
93%	-	95%	7
90%	-	92%	8
87%	-	89%	9
below	-	86%	10

II. Customer Satisfaction

A. General Description:

The Customer Satisfaction Indicator measures the public's perception of the quality of the Company's service through an annual Customer Survey.

B. Formula and Data Source:

An independent survey firm conducts a customer's opinion survey in the first quarter of each calendar year.

The survey firm shall be selected by the Commission and shall be a competent, professional, and national recognized survey firm. The Company will provide a list of firms meeting the criteria from which the Commission shall make its selection.

The scales used in this indicator were developed from data obtained by a nationally recognized, professional survey firm's asking the questions listed below. If the survey firm is changed or different questions are asked, new scales will be developed which are compatible with the new data and will yield the same results as thought the questions used below had been asked. Should such a change occur, the last survey, asking the questions below, will be used until a new surveyor, questions, and/or compatible scales can be developed.

If there is considerable difference in the price of the surveying firms, the Commission will choose the lower cost firm. Provided, however, there is a reason to select a firm other than the lowest cost firm, the Commission will inform the Company as to the reason.

The survey shall accurately reflect the overall customer satisfaction of Company's customers using statistical methods generally accepted by the industry.

RIDER SCHEDULE 327
STABLE / RATE ADJUSTMENT RIDER

The following questions are asked as part of the customer opinion survey:

Have you or anyone in your household contacted Atmos Energy in the last 3 months (If yes, 1 month)? (If yes, to contact) Were you the person who made the contact? (If yes, continue to Q1, if no, ask to speak to the person who did or call back if they are not there) If not contact, thank and terminate.

1. *How did you contact Atmos Energy?*
   By calling on the phone
   *By visiting your local office**
   By calling the emergency 800 number
   Other. Please specify:

2. *What was the purpose of your call (or visit*) with Atmos Energy?*
   To inquire about or make changes to your account such as address change, etc. **(Go to Q 3)**
   To question the charges or payments on your bill **(Go to Q4)**
   *To make a payment at local office** **(Go to Q4a)**
   To turn on service or request non-emergency service **(Go to Q5)**
   To request emergency service – possible gas leak **(Go to Q6)**
   Other. Please specify: **(Go to Q3)**

3. *For the following statements, please tell me whether you entirely agree, mostly agree, mostly disagree, entirely disagree or don't know/don't remember.*
   It was easy and convenient to contact Atmos Energy.
   The representative listened and was knowledgeable.
   The representative was professional and courteous.
   The representative handled my inquiry or request in that one call (or visit).*

   Skip to Q7

7. *Considering the overall experience you described, were you very satisfied, somewhat satisfied, somewhat dissatisfied or very dissatisfied with the service level of Atmos Energy?*

8. *If very or somewhat dissatisfied response to Q7, why?*

Survey Firm collect/validate required info to close interview

4. *Considering only your interaction with the Atmos Energy representative, please tell me whether you entirely agree, mostly agree, mostly disagree, entirely disagree or don't know/don't remember with each of the following statements.*

It was easy and convenient to contact Atmos Energy.
The representative listened and was knowledgeable.
The representative was professional and courteous.
The representative handled my bill/payment inquiry or request in that one call (or visit).*

Skip to Q7

7. *Considering the overall experience you described, were you very satisfied, somewhat satisfied, somewhat dissatisfied or very dissatisfied with the service level of Atmos Energy?*

8. If very or somewhat dissatisfied response to Q7, why?

Survey Firm collect/validate required info to close interview

4.a. *Considering only your visit to the local office, please tell me whether you entirely agree, mostly agree, mostly disagree, entirely disagree or don't know/don't remember with each of the following statements.*

It was easy and convenient to make a payment.
The office representative (if assistance) was professional and courteous.

Skip to Q7

7. *Considering the overall experience you described, were you very satisfied, somewhat satisfied, somewhat dissatisfied or very dissatisfied with the service level of Atmos Energy?*

8. If very or somewhat dissatisfied response to Q7, why?

Survey Firm collect/validate required info to close interview

5. *For the following statements, please tell me whether you entirely agree, mostly agree, mostly disagree, entirely disagree or don't know/don't remember.*

It was easy and convenient to contact Atmos Energy.
The representative on the call (or visit) listened and was knowledgeable.*
The representative on the call (or visit") was professional and courteous.
The representative handled my inquiry or request in that one call (or visit).*
The Atmos technician arrived at my residence on time.
The Atmos technician was professional and courteous.
The Atmos technician addressed my issue with that visit.

Skip to Q7

7. *Considering the overall experience you described, were you very satisfied, somewhat satisfied, somewhat dissatisfied or very dissatisfied with the service level of Atmos Energy?*

8. If very or somewhat dissatisfied response to Q7, why?

Survey Firm collect/validate required info to close interview

6. *For the following statements, please tell me whether you entirely agree, mostly agree, mostly disagree, entirely disagree or don't know/don't remember.*

It was easy and convenient to contact Atmos Energy.
The representative on the call (or visit") listened and was knowledgeable.
The representative on the call (or visit") was professional and courteous.
The Atmos technician arrived at my residence quickly.
The Atmos technician was professional and courteous.
The Atmos technician addressed the issue promptly.

7. *Considering the overall experience you described, were you very satisfied, somewhat satisfied, somewhat dissatisfied or very dissatisfied with the service level of Atmos Energy?*

8. If very or somewhat dissatisfied response to Q7, why?

Survey Firm collect/validate required info to close interview

RIDER SCHEDULE 327
STABLE / RATE ADJUSTMENT RIDER

Customer Satisfaction Index (CSI)

The Index calculation takes into account the results of: The overall customer experience question (Q7); and the four (4) service performance factor questions with regard to a call inquiry (or visit), and when applicable up to six (6) service performance factor questions with regard to an inquiry and service technician visit.

A factor index will be developed for each of the following six (6) performance factor questions. The indices are formed based upon the ratios of entirely agree and mostly agree responses for each question to the total number of customers expressing an opinion. The favorable rating ratio becomes the factor index.

- *It was easy and convenient to contact (if office, visit) Atmos Energy.*
- *The representative listened and was knowledgeable.*
- *The representative was professional and courteous: and/or the technician was professional and courteous.*
- *The representative handled my inquiry or request in that one call.*
- *The Atmos technician arrived on time; or the Atmos technician arrived quickly (if emergency service call).*
- *The Atmos technicians resolved the issue with visit; or addressed the issue promptly (if Emergency service call).*

The average of factor index ratings (sum of indices divided by 6) is used to create a Composite Factor rating. An Overall Experience rating is created from Q7 customer satisfaction results with the rating based upon the ratio of very and somewhat satisfied responses to the total number of customers expressing an opinion. The Composite Factor rating and Overall Experience rating are weighted equally to form the Index.

Customer Satisfaction Indicator

The Customer Satisfaction Indicator (CSI) score shall be the simple average of the scores for the Composite Factor index rating and the Overall Experience index rating, such that:

$$\text{CSI} \square \frac{\text{Composite Factor rating} \square \text{Overall Experience rating}}{2}$$

The Customer Satisfaction Score shall be determined using the following formula:

Customer Satisfaction Score □ (30 x CSI) - 16

The score used for the Customer Satisfaction Score shall fall between 0 and 10.

III. Weighting

Company's scores on the Performance Indicator are weighted and averaged as follows:

Performance Score	X	Weight	□	Weighted Score
Customer price	X	.75	□	
Customer satisfaction	X	.25	□	
		1.00		

COMPANY'S PERFORMANCE SCORE (CPS) _____

The Company's Performance Adjuster (PA) is calculated as follows:

(CPS X .10) - .50 □ PA

APPENDIX "E"
Page 7
PERFORMANCE INDICATORS

Tariff for Gas Service

Mid-Tex Division
Atmos Energy Corporation
5420 LBJ Freeway, Suite 1557
Dallas, Texas 75240

I. Purpose:

This mechanism is designed to provide annual earnings transparency. All rate calculations under this tariff shall be made on a system wide basis. If, through the implementation of the provisions of this mechanism, it is determined that rates should be decreased or increased, then rates will be adjusted accordingly in the manner set forth herein. The rate adjustments implemented under this mechanism will reflect annual changes in the Company s cost of service and rate base. This Rider DARR will be effective for the period commencing with the Company s first DARR filing on or before January 15, 2012.

II. Definitions

a) The **Annual Evaluation Date** shall be the date the Company will make its annual filing under this mechanism. The Annual Evaluation Date shall be no earlier than January 2nd nor later than January 15th of each year. This filing shall be made in electronic form where practicable.

b) **Audited Financial Data** shall mean the Company s books and records related to the Company s Mid-Tex operating area and shared services operations. Audited Financial Data shall not require the schedules and information provided under this tariff to undergo a separate financial audit by an outside auditing firm similar to the Company s annual financial audit.

c) The **Company** is defined as Amos Energy Corporation s Mid-Tex Division.

d) The **Test Period** is defined as the twelve month period ending September 30, of each preceding calendar year (*i.e.* the Company s January 15, 2012 filing will be based on the twelve month period ending September 30, 2011).

e) The **Rate Effective Period** is defined as the twelve-month period commencing June 1 and ending when subsequent rates are implemented pursuant to a final order from a regulatory authority.

f) **Final Order** is defined as the most recent final order establishing the Company s latest effective rates for customers within the City of Dallas.

III. Rate Review Mechanism

The Company shall file with the City of Dallas the schedules specified below for the Test Period, with the filing to be made by the Annual Evaluation Date following the end of the Test Period. The schedules will be based upon the Company s Audited Financial Data, as adjusted, and will include the following:

a) Test Period ending balances for actual gross plant in service, accumulated depreciation, accumulated deferred income taxes, inventory, working capital, and other rate base components will be used for the calculation of rates for the Rate Effective Period. The ratemaking treatments, principles, findings and adjustments included in the Final Order will apply except when a departure from those treatments, principles, findings or adjustments is justified by changed circumstances. Regulatory adjustments due to prior regulatory rate base adjustment disallowances will be maintained. Cash working capital will be calculated using the lead/lag days approved in the Final Order.

b) Depreciation rates booked in the period will be those approved in the Final Order, or the depreciation rates most recently approved for the Mid-Tex Division and the Shared Services Division by the Railroad Commission of Texas, as applicable, if and only if the City of Dallas has the right to participate in the subsequent Railroad Commission of Texas proceeding with a full

right to have it s reasonable expenses reimbursed. All calculation methodologies will be those approved in the Final Order except where noted or included in this tariff. In addition, the Company shall exclude from operating and maintenance expense the discretionary costs to be disallowed from Rider DARR filings listed in the DARR Schedules and Information section of this tariff.

c) Return on Equity (ROE) shall be maintained at 10.1%.

d) Long-term cost of debt will be the actual thirteen month average for the Test Period. Capital structure will be the actual thirteen month average Test Period ratio of long-term debt and equity.

e) All applicable accounting adjustments along with all supporting work papers. Such adjustments may include:

   1) Pro-forma adjustments to update and annualize costs and revenue billing determinants for the Rate Effective Period.

   2) Pro-forma or other adjustments required to properly account for atypical, unusual, or nonrecurring events recorded during the Test Period.

f) Shared Services allocation factors shall be recalculated each year based on the latest component factors used during the Test Period, but the methodology used will be that approved in the Final Order.

IV. Calculation of Rate Adjustment

a) The Company shall provide additional schedules indicating the following revenue deficiency/sufficiency calculations using the methodology accepted in the Final Order. The result shall be reflected in the proposed new rates to be established for the Rate Effective Period. In calculating the required rate adjustments, such adjustments will be apportioned between the customer charge and usage charge with the Residential and the Commercial customer charges being rounded to the nearest $0.25.

b) The Company may also adjust rates for the Rate Effective Period to include recovery of any known and measurable changes to operating and maintenance costs including, but not limited to, payroll and compensation expense, benefit expense, pension expense, insurance costs, materials and supplies, bad debt costs, medical expense, transportation and building and lease costs for the Rate Effective Period. Provided, however, that adjustments may only be made for costs that are reasonable and necessary.

c) Effective with the Company s DARR filing on January 15, 2013, the Company may include in its rate base calculation all direct, incremental investment and costs associated with its Rider IR steel service line replacement program and request reconciliation of the Rider IR regulatory asset account.

   1. Upon implementation of new, final rates that include recovery for all direct, incremental costs and investment associated with the Company s steel service line replacement program, the Company shall cease to charge the Rider IR monthly rate attributable to this program.

2. Notwithstanding IV(c)(1), the Company shall be entitled to separately recover the Rider IR monthly rate attributable to its steel service line replacement program until such time as new, final rates reflective of steel service line replacement costs and investment have been established pursuant to either (i) a DARR adjustment or (ii) a Statement of Intent rate case establishing the Company's latest effective rates for customers within the City of Dallas.

d) The regulatory authority may disallow any net plant investment that is not shown to be prudently incurred. Approval by the regulatory authority of net plant investment pursuant to the provisions of this tariff shall permit the Company to earn a return on that net investment for the Effective Period which shall not be subject to refund if in a subsequent review a portion of the plant is determined to be imprudently incurred.

e) The Company shall provide a schedule demonstrating the "proof of revenues" relied upon to calculate the proposed rate for the Rate Effective Period. The proposed rates shall conform as closely as is practicable to the revenue allocation principles approved in the Final Order.

V. Attestation

A sworn statement shall be filed by an Officer of the Mid-Tex Division affirming that the filed schedules are in compliance with the provisions of this mechanism and are true and correct to the best of his/her knowledge, information and belief. No testimony shall be filed, but a brief narrative explanation shall be provided of any changes to corporate structure, accounting methodologies or allocation of common costs.

VI. Evaluation Procedures

The City of Dallas shall have 135 days to review and render a decision on the Company's filed schedules and work papers. The Company will be prepared to provide all supplemental information as may be requested to ensure adequate review by the relevant regulatory authority. The Company shall not unilaterally impose any limits upon the provision of supplemental information and such information shall be provided within ten (10) working days of the original request. The regulatory authority may propose any adjustments it determines to be required to bring the schedules into compliance with the above provisions.

During the 135 day period, the Company and the regulatory authority will work collaboratively and seek agreement on the proposed adjustments to the Company's schedule and proposed rates. If agreement has been reached by the Company and the regulatory authority, the regulatory authority shall authorize an increase or decrease to the Company's rates so as to achieve the revenue levels indicated for the Rate Effective Period. If, at the end of the 135 day period, the Company and the regulatory authority have not reached agreement on the proposed adjustments, the Company shall have the right to appeal the regulatory authority's action or inaction to the Railroad Commission of Texas. Upon the filing of an appeal of the City's order relating to an annual DARR filing with the Railroad Commission of Texas, the City shall not oppose the implementation of rates subject to refund or advocate the imposition of a 3rd party surety bond by the Company.

VII. Reconsideration and Appeal

Orders issued pursuant to this mechanism are ratemaking orders and shall be subject to appeal under Sections 102.001(b) and 103.021, et seq., of the Texas Utilities Code (Vernon 2007).

VIII. Notice

Notice of this annual DARR filing shall be provided by including the notice, in conspicuous form, in the bill of each directly affected customer no later than forty-five (45) days after the Company makes its annual filing pursuant to this tariff. The notice to customers shall include the following information:

a) a description of the proposed revision of rates and schedules;

b) the effect the proposed revision of rates is expected to have on the rates applicable to each customer class and on an average bill for each affected customer;

c) the service area or areas in which the proposed rate adjustment would apply;

d) the date the proposed rate adjustment was filed with the regulatory authority; and

e) the Company s address, telephone number and website where information concerning the proposed rate adjustment may be obtained.

Company shall notice customers again by bill insert as soon as practical after final DARR rates are ordered by the City and agreed to by the Company if the agreed increase or decrease in rates is materially different than the initial notice.

IX. DARR Schedules and Information

The following types of employee reimbursed expenses and directly incurred costs are to be removed from all expense and rate base amounts included within Rider DARR filings for the Test Period and for the Rate Effective Period:

- Amounts incurred for travel, meals or entertainment of employee spouses, domestic partners, significant others, children and pets.
- Amounts for air travel that exceed published commercial coach air fares.
- Amounts incurred for excessive rates for hotel rooms.
- Amounts for alcoholic beverages.
- Amounts paid for admission to entertainment, sports, art or cultural events, and all event sponsorship costs.
- Amounts for social club dues or fees.

I. Purpose:

This mechanism is designed to provide annual earnings transparency. All rate calculations under this tariff shall be made on a system wide basis. If, through the implementation of the provisions of this mechanism, it is determined that rates should be decreased or increased, then rates will be adjusted accordingly in the manner set forth herein. The rate adjustments implemented under this mechanism will reflect annual changes in the Company's cost of service and rate base. This Rider RRM will be effective for the period commencing with the Company's RRM filing on April 1, 2011, and concluding with the implementation of new, final rates established pursuant to the general rate case that Atmos will file on or before June 1, 2013.

II. Definitions

a) The **Annual Evaluation Date** shall be the date the Company will make its annual filing under this mechanism. The Annual Evaluation Date shall be no later than April 1, of each year. This filing shall be effective in electronic form where practicable.

b) **Audited Financial Data** shall mean the Company's books and records related to the Company's Mid-Tex operating area and shared services operations. Audited Financial Data shall not require the schedules and information provided under this tariff to undergo a separate financial audit by an outside auditing firm similar to the Company's annual financial audit.

c) The **Evaluation Period** is defined as the twelve month period ending December 31, of each calendar year.

d) The **Rate Effective Period** is defined as the later of the twelve month period for which rates determined under this mechanism will be in effect or subsequent rates are implemented.

e) **Per Connection Basis** is defined as the existing average number of Mid-Tex active meters to customers during the Evaluation Period.

f) **Final Order** is defined as the most recent order establishing the Company's latest effective rates for the area in which the mechanism is implemented, and shall include municipal rate ordinances and resolutions.

III. Rate Review Mechanism

The Company shall file with each regulatory authority having original jurisdiction over the Company's rates the schedules specified below for the Evaluation Period, with the filing to be made by the Annual Evaluation Date following the end of the Evaluation Period. The schedules, which will be based upon the Company's Audited Financial Data, as adjusted, and provided in the same format as Atmos RRM filing with municipalities on March 15, 2010, will exclude a true-up computation, but will include the following:

a) Evaluation Period ending balances for actual gross plant in service, accumulated depreciation, accumulated deferred income taxes, inventory, working capital, and other rate base components will be used for the calculation of rates for the Rate Effective Period. The ratemaking treatments, principles, findings and adjustments included in the Final Order will apply. Regulatory adjustments due to prior regulatory rate base adjustment disallowances will be maintained. Cash working capital will be calculated using the lead/lag days approved in the Final Order.

Accumulated deferred income taxes (ADIT) will be calculated using the methodology used in the Final Order. The RRM Schedules & Information section of this tariff identifies those ADIT components to be included in the calculation of rate base for both the Evaluation Period and Rate Effective Period calculations.

b) Depreciation rates booked in the period will be those approved in the Final Order, or the rate most recently approved. All calculation methodologies will be those approved in the Final Order except where noted or included in this tariff, or in the most recent order addressing the methodology. In addition, the Company shall exclude from operating and maintenance expense the discretionary costs to be disallowed from Rider RRM filings listed in the RRM Schedules and Information section of this tariff.

c) Return on Equity (ROE) shall be maintained at 9.7%.

d) Cost of debt will reflect actual cost for the Evaluation Period. Evaluation Period ending balances for cost of debt and capital structure will be used for the calculation of rates for the Rate Effective Period. Capital structure will be the actual Evaluation Period ratio of long-term debt and equity, with percentage equity not to exceed 50%, based on the calculation methodology outcomes used above.

e) All applicable accounting adjustments along with all supporting work papers. Such adjustments may include:

   1) Pro-forma adjustments to update and annualize costs and revenue billing determinants for the Rate Effective Period.

   2) Pro-forma or other adjustments required to properly account for atypical, unusual, or nonrecurring events recorded during the Evaluation Period.

f) Shared Services allocation factors shall be recalculated each year based on the latest component factors used during the Evaluation Period, but the methodology used will be that approved in the Final Order.

g) Any changes to corporate structure or allocation of common costs will include narrative explanations with the filing.

IV. Calculation of Rate Adjustment

a) The Company shall provide additional schedules indicating the following revenue deficiency/sufficiency calculations using the methodology accepted in the Final Order with the exception of any allowance for a true-up component in the April 1, 2011 or the April 1, 2012 RRM filings. Evaluation Period ending balances will be used for the calculation of rates for the Rate Effective Period. These schedules shall identify the rate adjustments necessary for the setting of prospective rates for the Rate Effective Period. The result shall be reflected in the proposed new rates to be established for the Rate Effective Period. In calculating the required rate adjustments, such adjustments will be made pro-ratably to the customer charge and usage charge based upon actual revenue generated, as adjusted under the Company's approved Weather Normalization

Adjustment (WNA) Rider. Provided, however, that neither the Residential nor the Commercial customer charges may increase more than 20% per year.

b) The Company may also adjust rates for the Rate Effective Period to include recovery of any known and measurable changes to operating and maintenance costs including, but not limited to, payroll and compensation expense, benefit expense, pension expense, insurance costs, materials and supplies, bad debt costs, medical expense, transportation and building and lease costs for the Rate Effective Period. Provided, however, that adjustments may only be made for costs that are reasonable and necessary. Additionally, utility plant and rate base for the Rate Effective Period will be established by using the Evaluation Period ending balances, including associated changes in depreciation and amortization expense and taxes. In calculating the Company's known and measurable changes for prospective RRM adjustment purposes, the following limitations will apply, on a Per Connection Basis.

1. Operating and Maintenance expenses per connection for the Rate Effective Period cannot increase more than 5% per year without specific identification and justification. Any proposed adjustment above 5% per year, is subject to the provisions of the Evaluation Procedures of this tariff. Such procedures provide that the regulatory authority will review the proposed adjustment and that the Company and regulatory authority will work collaboratively to seek agreement on the proposed adjustments to the Company's schedules and proposed rates. Justification for such expenditures over the cap shall include an event or combination of events beyond the control of the Company. The beginning adjusted Operation and Maintenance expense per connection for the 2007 RRM Evaluation Period will be limited to not exceed $151 million divided by the connections for the period. The increase in adjusted Operation and Maintenance expenses per connection for the 2008 Rate Effective Period and the subsequent Rate Effective periods cannot exceed 5% per year, without specific identification and justification

2. Net plant investment per connection for the Rate Effective Period cannot increase more than 5% per year without specific identification and justification. Any proposed adjustment above 5% per year, is subject to the provisions of the Evaluation Procedures of this tariff. Such procedures provide that the regulatory authority will review the proposed adjustment and that the Company and regulatory authority will work collaboratively to seek agreement on the proposed adjustments to the Company's schedules and proposed rates. However, in performing a cap test to verify compliance, the Company shall exclude any changes in net plant investment associated with federal, state, or local mandates related to safety, compliance, or road moves, including steel service line replacement program costs incurred prior to October 1, 2010. The initial 2008 rate will be set using net plant limited to not exceed [$1,243,607,206 divided by average active meters for the 12 months ended June 30 2007] times 1.025 times the average active meters for calendar year 2007. Subsequent filing calculations of net plant investment will be made using the same method used in the Company's September 20, 2007 Statement of Intent except that Evaluation Period ending balances will be used for net plant in the calculation of rates for the Rate Effective Period.

   The rate increase limitations set forth in this tariff shall not preclude the Company from recovering any excluded net plant costs during a subsequent Evaluation Period in which

the 5% limitation for net plant investment is not reached or in a subsequent Statement of Intent case. To the extent that the Company seeks to recover any excluded net plant costs during a subsequent Evaluation Period in which the 5% limitation for net plant investment is not reached or in a subsequent Statement of Intent case, the Company shall identify these costs as a specific line item in the schedule accompanying the RRM rate adjustment filing.

The regulatory authority may disallow any net plant investment that is not shown to be prudently incurred. Approval by the regulatory authority of net plant investment pursuant to the provisions of this tariff shall constitute a finding that such net plant investment was prudently incurred. Such finding of prudence shall not be subject to further review in a subsequent Evaluation Period or Statement of Intent filing.

c) Notwithstanding the limitations in subparts IV (a) through (b) of this tariff, the Company shall be entitled to separately adjust rates for the Rate Effective Period to include recovery for direct incremental costs associated with a steel service line replacement program incurred on and after October 1, 2010, a return on equity of 9.0% for such incremental costs as capitalized, depreciation, and applicable taxes. Capital structure will be the actual Evaluation Period ratio of long-term debt and equity, with percentage equity not to exceed 50%, based on the calculation methodology outcomes used above. Rate recovery associated with a steel service line replacement program shall be recovered through the Residential and Commercial customer charges and shall not be subject to or included in the rate increase limitations set forth in IV (a) through (b) of this tariff. Current year recovery factors are presumed to be $0.15 for residential customers and $0.41 for commercial customers. The rates will be adjusted annually, however, in no case will the per customer monthly cost recovery factors attributable to a steel service line replacement program exceed $0.44 for residential customers or $1.22 for commercial customers, prior to or during the pendency of the Company's next Statement of Intent case. Moreover, the per customer amount attributable to cost recovery for a steel service line replacement program shall be subject to review by the regulatory authority in a subsequent Evaluation Period and all costs associated with a steel service line replacement program will be subject to a prudence/reasonableness review in the Company's next Statement of Intent rate case.

d) The Company shall provide a schedule demonstrating the proof of revenues relied upon to calculate the proposed rate for the Rate Effective Period. The proposed rates shall conform as closely as is practicable to the revenue allocation principles approved in the Final Order.

V. Attestation

A sworn statement shall be filed by the Company's Chief Officer in Charge of Mid-Tex Operations affirming that the filed schedules are in compliance with the provisions of this mechanism and are true and correct to the best of his/her knowledge, information and belief. No testimony shall be filed, but a brief narrative explanation shall be provided of any changes to corporate structure or allocation of common costs.

VI. Evaluation Procedures

The regulatory authority having original jurisdiction over the Company's rates shall have no less than ninety (90) days to review the Company's filed schedules and work papers. The Company will be

prepared to provide all supplemental information as may be requested to ensure adequate review by the relevant regulatory authority. The Company shall not unilaterally impose any limits upon the provision of supplemental information and such information shall be provided within ten (10) working days of the original request. The regulatory authority may propose any adjustments it determines to be required to bring the schedules into compliance with the above provisions.

During and following the ninety (90) day review period and a thirty (30) day response period, the Company and the regulatory authority will work collaboratively and seek agreement on, the proposed adjustments to the Company's schedule and proposed rates. If agreement has been reached by the Company and the regulatory authority, the regulatory authority shall authorize an increase or decrease to the Company's rates so as to achieve the revenue levels indicated for the Rate Effective Period. If, at the end of the thirty (30) day response period, the Company and the regulatory authority have not reached agreement on the proposed adjustments, the Company shall have the right to appeal the regulatory authority's action or inaction to the Railroad Commission of Texas. Upon the filing of any appeal, the Company shall have the right to implement the proposed RRM rate adjustment, including the adjustment attributable to steel service line replacement program costs, subject to refund.

Rates established pursuant to the Rate Review Mechanism, if approved as provided herein, shall be effective on August 15 of each year.

VII. Reconsideration and Appeal

Orders issued pursuant to this mechanism are ratemaking orders and shall be subject to appeal under Sections 102.001(b) and 103.021, et seq., of the Texas Utilities Code (Vernon 2007).

VIII. Notice

Notice of the annual Rate Review Mechanism filing shall be provided pursuant to Section 104.103, TEX. UTIL. CODE ANN. no later than forty-five (45) days after the Company makes its annual filing pursuant to this tariff. The notice to customers shall include the following information:

a) a description of the proposed revision of rates and schedules;

b) the effect the proposed revision of rates is expected to have on the rates applicable to each customer class and on an average bill for each affected customer;

c) the service area or areas in which the proposed rate adjustment would apply;

d) the date the proposed rate adjustment was filed with the regulatory authority; and

e) the Company's address, telephone number and website where information concerning the proposed rate adjustment may be obtained.

IX. RRM Schedules and Information

a. Accumulated Deferred Income Tax (ADIT) Items To Be Recognized in Rate Base

The following list identifies those ADIT components to be included in the calculation of rate base for both the Evaluation Period and Rate Effective Period calculations:

Mid-Tex:
Gas Plant in Service
Insurance Accruals
Benefit Accruals
Deferred Expense Projects
Allowance for Doubtful Accounts
Customer Advances
UNICAP Section 263A Costs (which shall be removed from Atmos Mid-Tex when these costs are transferred to Atmos Pipeline Texas)
Regulatory Asset - Mid Tex
Regulatory Liability - Mid-Tex
Other Plant

SSU - Customer Support:
Gas Plant in Service

SSU - General Office:
Gas Plant in Service
Insurance Accruals
Benefits Accruals
Deferred Expense Projects
Prepaid Expenses
Regulatory Liability - Atmos 109
FAS 115 Adjustment
Treasury Lock Adjustment
Revenue Agent Report Carryforward Adjustments 1990-1985
Tax Net Operating Loss Credit Carryforwards
State Bonus Depreciation
R & D Credit Valuation Allowance
Other Plant

b. Discretionary Costs to Be Disallowed from Rider RRM filings

The following types of employee reimbursed expenses and directly incurred costs are to be removed from all expense and rate base amounts included within Rider RRM filings for the Evaluation Period and for the Rate Effective Period:

Amounts incurred for travel, meals or entertainment of employee spouses.
Amounts for air travel that exceed published commercial coach air fares.
Amounts incurred for hotel rooms exceeding $250 per night inclusive of taxes and fees assessed on such rooms.
Amounts for alcoholic beverages.

Amounts paid for admission to entertainment, sports, art or cultural events, and all event sponsorship costs.
Amounts for social club dues or fees.

I. Purpose:

This mechanism is designed to provide annual earnings transparency. All rate calculations under this tariff shall be made on a system wide basis. If, through the implementation of the provisions of this mechanism, it is determined that rates should be decreased or increased, then rates will be adjusted accordingly in the manner set forth herein. The rate adjustments implemented under this mechanism will reflect annual changes in the Company's cost of service and rate base. This Rider RRM will be effective for the period commencing with the Company's RRM filing on April 1, 2011, and concluding with the implementation of new, final rates established pursuant to the general rate case that Atmos will file on or before June 1, 2013.

II. Definitions

a) The **Annual Evaluation Date** shall be the date the Company will make its annual filing under this mechanism. The Annual Evaluation Date shall be no later than April 1, of each year. This filing shall be effective in electronic form where practicable.

b) **Audited Financial Data** shall mean the Company's books and records related to the Company's Mid-Tex operating area and shared services operations. Audited Financial Data shall not require the schedules and information provided under this tariff to undergo a separate financial audit by an outside auditing firm similar to the Company's annual financial audit.

c) The **Evaluation Period** is defined as the twelve month period ending December 31, of each calendar year.

d) The **Rate Effective Period** is defined as the later of the twelve month period for which rates determined under this mechanism will be in effect or subsequent rates are implemented.

e) **Per Connection Basis** is defined as the existing average number of Mid-Tex active meters to customers during the Evaluation Period.

f) **Final Order** is defined as the most recent order establishing the Company's latest effective rates for the area in which the mechanism is implemented, and shall include municipal rate ordinances and resolutions.

III. Rate Review Mechanism

The Company shall file with each regulatory authority having original jurisdiction over the Company's rates the schedules specified below for the Evaluation Period, with the filing to be made by the Annual Evaluation Date following the end of the Evaluation Period. The schedules, which will be based upon the Company's Audited Financial Data, as adjusted, and provided in the same format as Atmos RRM filing with municipalities on March 15, 2010, will exclude a true-up computation, but will include the following:

a) Evaluation Period ending balances for actual gross plant in service, accumulated depreciation, accumulated deferred income taxes, inventory, working capital, and other rate base components will be used for the calculation of rates for the Rate Effective Period. The ratemaking treatments, principles, findings and adjustments included in the Final Order will apply. Regulatory adjustments due to prior regulatory rate base adjustment disallowances will be maintained. Cash working capital will be calculated using the lead/lag days approved in the Final Order.

Accumulated deferred income taxes (ADIT) will be calculated using the methodology used in the Final Order. The RRM Schedules & Information section of this tariff identifies those ADIT components to be included in the calculation of rate base for both the Evaluation Period and Rate Effective Period calculations.

b) Depreciation rates booked in the period will be those approved in the Final Order, or the rate most recently approved. All calculation methodologies will be those approved in the Final Order except where noted or included in this tariff, or in the most recent order addressing the methodology. In addition, the Company shall exclude from operating and maintenance expense the discretionary costs to be disallowed from Rider RRM filings listed in the RRM Schedules and Information section of this tariff.

c) Return on Equity (ROE) shall be maintained at 9.7%.

d) Cost of debt will reflect actual cost for the Evaluation Period. Evaluation Period ending balances for cost of debt and capital structure will be used for the calculation of rates for the Rate Effective Period. Capital structure will be the actual Evaluation Period ratio of long-term debt and equity, with percentage equity not to exceed 50%, based on the calculation methodology outcomes used above.

e) All applicable accounting adjustments along with all supporting work papers. Such adjustments may include:

   1) Pro-forma adjustments to update and annualize costs and revenue billing determinants for the Rate Effective Period.

   2) Pro-forma or other adjustments required to properly account for atypical, unusual, or nonrecurring events recorded during the Evaluation Period.

f) Shared Services allocation factors shall be recalculated each year based on the latest component factors used during the Evaluation Period, but the methodology used will be that approved in the Final Order.

g) Any changes to corporate structure or allocation of common costs will include narrative explanations with the filing.

IV. Calculation of Rate Adjustment

a) The Company shall provide additional schedules indicating the following revenue deficiency/sufficiency calculations using the methodology accepted in the Final Order with the exception of any allowance for a true-up component in the April 1, 2011 or the April 1, 2012 RRM filings. Evaluation Period ending balances will be used for the calculation of rates for the Rate Effective Period. These schedules shall identify the rate adjustments necessary for the setting of prospective rates for the Rate Effective Period. The result shall be reflected in the proposed new rates to be established for the Rate Effective Period. In calculating the required rate adjustments, such adjustments will be made pro-ratably to the customer charge and usage charge based upon actual revenue generated, as adjusted under the Company's approved Weather Normalization

Adjustment (WNA) Rider. Provided, however, that neither the Residential nor the Commercial customer charges may increase more than 20% per year.

b) The Company may also adjust rates for the Rate Effective Period to include recovery of any known and measurable changes to operating and maintenance costs including, but not limited to, payroll and compensation expense, benefit expense, pension expense, insurance costs, materials and supplies, bad debt costs, medical expense, transportation and building and lease costs for the Rate Effective Period. Provided, however, that adjustments may only be made for costs that are reasonable and necessary. Additionally, utility plant and rate base for the Rate Effective Period will be established by using the Evaluation Period ending balances, including associated changes in depreciation and amortization expense and taxes. In calculating the Company's known and measurable changes for prospective RRM adjustment purposes, the following limitations will apply, on a Per Connection Basis.

1. Operating and Maintenance expenses per connection for the Rate Effective Period cannot increase more than 5% per year without specific identification and justification. Any proposed adjustment above 5% per year, is subject to the provisions of the Evaluation Procedures of this tariff. Such procedures provide that the regulatory authority will review the proposed adjustment and that the Company and regulatory authority will work collaboratively to seek agreement on the proposed adjustments to the Company's schedules and proposed rates. Justification for such expenditures over the cap shall include an event or combination of events beyond the control of the Company. The beginning adjusted Operation and Maintenance expense per connection for the 2007 RRM Evaluation Period will be limited to not exceed $151 million divided by the connections for the period. The increase in adjusted Operation and Maintenance expenses per connection for the 2008 Rate Effective Period and the subsequent Rate Effective periods cannot exceed 5% per year, without specific identification and justification

2. Net plant investment per connection for the Rate Effective Period cannot increase more than 5% per year without specific identification and justification. Any proposed adjustment above 5% per year, is subject to the provisions of the Evaluation Procedures of this tariff. Such procedures provide that the regulatory authority will review the proposed adjustment and that the Company and regulatory authority will work collaboratively to seek agreement on the proposed adjustments to the Company's schedules and proposed rates. However, in performing a cap test to verify compliance, the Company shall exclude any changes in net plant investment associated with federal, state, or local mandates related to safety, compliance, or road moves, including steel service line replacement program costs incurred prior to October 1, 2010. The initial 2008 rate will be set using net plant limited to not exceed [$1,243,607,206 divided by average active meters for the 12 months ended June 30 2007] times 1.025 times the average active meters for calendar year 2007. Subsequent filing calculations of net plant investment will be made using the same method used in the Company's September 20, 2007 Statement of Intent except that Evaluation Period ending balances will be used for net plant in the calculation of rates for the Rate Effective Period.

   The rate increase limitations set forth in this tariff shall not preclude the Company from recovering any excluded net plant costs during a subsequent Evaluation Period in which

the 5% limitation for net plant investment is not reached or in a subsequent Statement of Intent case. To the extent that the Company seeks to recover any excluded net plant costs during a subsequent Evaluation Period in which the 5% limitation for net plant investment is not reached or in a subsequent Statement of Intent case, the Company shall identify these costs as a specific line item in the schedule accompanying the RRM rate adjustment filing.

The regulatory authority may disallow any net plant investment that is not shown to be prudently incurred. Approval by the regulatory authority of net plant investment pursuant to the provisions of this tariff shall constitute a finding that such net plant investment was prudently incurred. Such finding of prudence shall not be subject to further review in a subsequent Evaluation Period or Statement of Intent filing.

c) Notwithstanding the limitations in subparts IV (a) through (b) of this tariff, the Company shall be entitled to separately adjust rates for the Rate Effective Period to include recovery for direct incremental costs associated with a steel service line replacement program incurred on and after October 1, 2010, a return on equity of 9.0% for such incremental costs as capitalized, depreciation, and applicable taxes. Capital structure will be the actual Evaluation Period ratio of long-term debt and equity, with percentage equity not to exceed 50%, based on the calculation methodology outcomes used above. Rate recovery associated with a steel service line replacement program shall be recovered through the Residential and Commercial customer charges and shall not be subject to or included in the rate increase limitations set forth in IV (a) through (b) of this tariff. Current year recovery factors are presumed to be $0.15 for residential customers and $0.41 for commercial customers. The rates will be adjusted annually, however, in no case will the per customer monthly cost recovery factors attributable to a steel service line replacement program exceed $0.44 for residential customers or $1.22 for commercial customers, prior to or during the pendency of the Company's next Statement of Intent case. Moreover, the per customer amount attributable to cost recovery for a steel service line replacement program shall be subject to review by the regulatory authority in a subsequent Evaluation Period and all costs associated with a steel service line replacement program will be subject to a prudence/reasonableness review in the Company's next Statement of Intent rate case.

d) The Company shall provide a schedule demonstrating the proof of revenues relied upon to calculate the proposed rate for the Rate Effective Period. The proposed rates shall conform as closely as is practicable to the revenue allocation principles approved in the Final Order.

V. Attestation

A sworn statement shall be filed by the Company's Chief Officer in Charge of Mid-Tex Operations affirming that the filed schedules are in compliance with the provisions of this mechanism and are true and correct to the best of his/her knowledge, information and belief. No testimony shall be filed, but a brief narrative explanation shall be provided of any changes to corporate structure or allocation of common costs.

VI. Evaluation Procedures

The regulatory authority having original jurisdiction over the Company's rates shall have no less than ninety (90) days to review the Company's filed schedules and work papers. The Company will be

prepared to provide all supplemental information as may be requested to ensure adequate review by the relevant regulatory authority. The Company shall not unilaterally impose any limits upon the provision of supplemental information and such information shall be provided within ten (10) working days of the original request. The regulatory authority may propose any adjustments it determines to be required to bring the schedules into compliance with the above provisions.

During and following the ninety (90) day review period and a thirty (30) day response period, the Company and the regulatory authority will work collaboratively and seek agreement on, the proposed adjustments to the Company s schedule and proposed rates. If agreement has been reached by the Company and the regulatory authority, the regulatory authority shall authorize an increase or decrease to the Company s rates so as to achieve the revenue levels indicated for the Rate Effective Period. If, at the end of the thirty (30) day response period, the Company and the regulatory authority have not reached agreement on the proposed adjustments, the Company shall have the right to appeal the regulatory authority s action to the Railroad Commission of Texas. Upon the filing of any appeal, the Company shall have the right to implement the proposed RRM rate adjustment, including the adjustment attributable to steel service line replacement program costs, subject to refund.

Rates established pursuant to the Rate Review Mechanism, if approved as provided herein, shall be effective on August 15 of each year.

VII. Reconsideration and Appeal

Orders issued pursuant to this mechanism are ratemaking orders and shall be subject to appeal under Sections 102.001(b) and 103.021, et seq., of the Texas Utilities Code (Vernon 2007).

VIII. Notice

Notice of the annual Rate Review Mechanism filing shall be provided pursuant to Section 104.103, TEX. UTIL. CODE ANN. no later than forty-five (45) days after the Company makes its annual filing pursuant to this tariff. The notice to customers shall include the following information:

a) a description of the proposed revision of rates and schedules;

b) the effect the proposed revision of rates is expected to have on the rates applicable to each customer class and on an average bill for each affected customer;

c) the service area or areas in which the proposed rate adjustment would apply;

d) the date the proposed rate adjustment was filed with the regulatory authority; and

e) the Company s address, telephone number and website where information concerning the proposed rate adjustment may be obtained.

IX. RRM Schedules and Information

a. Accumulated Deferred Income Tax (ADIT) Items To Be Recognized in Rate Base

The following list identifies those ADIT components to be included in the calculation of rate base for both the Evaluation Period and Rate Effective Period calculations:

Mid-Tex:
Gas Plant in Service
Insurance Accruals
Benefit Accruals
Deferred Expense Projects
Allowance for Doubtful Accounts
Customer Advances
UNICAP Section 263A Costs (which shall be removed from Atmos Mid-Tex when these costs are transferred to Atmos Pipeline Texas)
Regulatory Asset - Mid Tex
Regulatory Liability - Mid-Tex
Other Plant

SSU - Customer Support:
Gas Plant in Service

SSU - General Office:
Gas Plant in Service
Insurance Accruals
Benefits Accruals
Deferred Expense Projects
Prepaid Expenses
Regulatory Liability - Atmos 109
FAS 115 Adjustment
Treasury Lock Adjustment
Revenue Agent Report Carryforward Adjustments 1990-1985
Tax Net Operating Loss Credit Carryforwards
State Bonus Depreciation
R & D Credit Valuation Allowance
Other Plant

b. Discretionary Costs to Be Disallowed from Rider RRM filings

The following types of employee reimbursed expenses and directly incurred costs are to be removed from all expense and rate base amounts included within Rider RRM filings for the Evaluation Period and for the Rate Effective Period:

Amounts incurred for travel, meals or entertainment of employee spouses.
Amounts for air travel that exceed published commercial coach air fares.
Amounts incurred for hotel rooms exceeding $250 per night inclusive of taxes and fees assessed on such rooms.
Amounts for alcoholic beverages.

Amounts paid for admission to entertainment, sports, art or cultural events, and all event sponsorship costs.
Amounts for social club dues or fees.

ATMOS energy

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Utilities Division
LA Public Service Commission

2012 MAR 30 AM 9:27
LA PUBLIC SERVICE COMMISSION

March 26, 2012

Division of Utilities
Louisiana Public Service Commission
602 N. 5th Street
Galvez Building, 12th Floor
Baton Rouge, LA 70802

Enclosed is the FERC Form 2, Annual Report of Major Natural Gas Companies, the Louisiana One Call form and letter, the one-page report of gas statistical data by month for our Atmos Energy Louisiana Division and Atmos Energy Louisiana Division state only pages for the calendar year 2011.

Please call me at (972) 855-3346 if you have any questions regarding the report.

Sincerely,

Ryan Ginty
Director, Financial Reporting

RECEIVED
BY THE
LOUISIANA PUBLIC
SERVICE COMMISSION
MAR 31 2012
ECONOMICS AND RATES
ANALYSIS DIVISION

Enclosures

ATMOS ENERGY CORPORATION (Louisiana Division)
Conversion from 14.95 to 14.73
MCF SALES @ 14.73 PSIA

Month/Yr	Residential	%	Commercial	%	Industrial	%	Total
Jan-11	3,058,929	73.0%	1,132,842	27.0%	0	0.0%	4,191,771
Feb-11	3,068,971	72.7%	1,153,220	27.3%	0	0.0%	4,222,191
Mar-11	1,422,327	66.2%	727,507	33.8%	0	0.0%	2,149,834
Apr-11	766,293	58.9%	535,578	41.1%	0	0.0%	1,301,871
May-11	605,306	54.8%	500,210	45.2%	0	0.0%	1,105,516
Jun-11	515,991	53.8%	442,283	46.2%	0	0.0%	958,274
Jul-11	469,414	53.0%	415,948	47.0%	0	0.0%	885,362
Aug-11	439,422	51.7%	410,215	48.3%	0	0.0%	849,637
Sep-11	466,635	52.2%	426,903	47.8%	0	0.0%	893,538
Oct-11	520,507	53.3%	456,248	46.7%	0	0.0%	976,755
Nov-11	880,529	60.6%	572,834	39.4%	0	0.0%	1,453,363
Dec-11	1,794,594	68.3%	834,200	31.7%	0	0.0%	2,628,794
Unbilled Revenue	(344,176)	76.8%	(104,177)	23.2%			(448,353)
Total	**13,664,742**	**64.6%**	**7,503,811**	**35.4%**	**0**	**0.0%**	**21,168,553**

REVENUE ($)

Month/Yr	Residential	%	Commercial	%	Industrial	%	Total
Jan-11	$28,276,648	72.4%	$10,791,176	27.6%	0	0.0%	$39,067,824
Feb-11	27,924,618	72.0%	10,836,054	28.0%	0	0.0%	38,760,672
Mar-11	16,792,715	68.9%	7,568,764	31.1%	0	0.0%	24,361,479
Apr-11	9,960,998	66.1%	5,097,924	33.9%	0	0.0%	15,058,922
May-11	8,866,482	64.5%	4,869,795	35.5%	0	0.0%	13,736,277
Jun-11	8,160,921	65.0%	4,403,290	35.0%	0	0.0%	12,564,211
Jul-11	7,866,709	65.1%	4,224,736	34.9%	0	0.0%	12,091,445
Aug-11	7,745,253	64.8%	4,209,290	35.2%	0	0.0%	11,954,543
Sep-11	7,772,056	64.7%	4,232,148	35.3%	0	0.0%	12,004,204
Oct-11	8,099,319	64.7%	4,424,121	35.3%	0	0.0%	12,523,440
Nov-11	11,090,647	66.4%	5,612,587	33.6%	0	0.0%	16,703,234
Dec-11	18,175,462	69.5%	7,959,778	30.5%	0	0.0%	26,135,240
Unbilled Revenue	(2,337,064)	71.3%	(940,362)	28.7%			(3,277,426)
Total	**$158,394,764**	**68.4%**	**$73,289,301**	**31.6%**	**$0**	**0.0%**	**231,684,065**

CUSTOMERS

Month/Yr	Residential	%	Commercial	%	Industrial	%	Total
Jan-11	325,193	93.9%	21,140	6.1%	0	0.0%	346,333
Feb-11	324,960	93.9%	21,148	6.1%	0	0.0%	346,108
Mar-11	325,047	93.9%	21,180	6.1%	0	0.0%	346,227
Apr-11	324,116	93.9%	21,002	6.1%	0	0.0%	345,118
May-11	323,326	93.9%	20,874	6.1%	0	0.0%	344,200
Jun-11	322,281	93.9%	20,829	6.1%	0	0.0%	343,110
Jul-11	320,894	93.9%	20,742	6.1%	0	0.0%	341,636
Aug-11	321,380	93.9%	20,730	6.1%	0	0.0%	342,110
Sep-11	320,255	93.9%	20,687	6.1%	0	0.0%	340,942
Oct-11	320,352	93.9%	20,736	6.1%	0	0.0%	341,088
Nov-11	321,535	93.9%	20,826	6.1%	0	0.0%	342,361
Dec-11	322,952	93.9%	20,991	6.1%	0	0.0%	343,943
Average	**322,691**	**93.9%**	**20,907**	**6.1%**	**0**	**0.0%**	**343,598**

MCF PURCHASES @ 14.73 PSIA

Month/Yr	Residential	%	Commercial	%	Industrial	%	Total
Jan-11	3,124,540	73.0%	1,155,652	27.0%	0	0.0%	4,280,192
Feb-11	2,036,474	72.7%	764,728	27.3%	0	0.0%	2,801,202
Mar-11	1,429,263	66.2%	729,745	33.8%	0	0.1%	2,159,008
Apr-11	675,008	58.9%	471,016	41.1%	0	0.0%	1,146,024
May-11	581,254	54.8%	479,429	45.2%	0	0.0%	1,060,683
Jun-11	509,099	53.8%	437,182	46.2%	0	0.0%	946,281
Jul-11	459,264	53.0%	407,272	47.0%	0	0.0%	866,536
Aug-11	425,225	51.7%	397,261	48.3%	0	0.0%	822,486
Sep-11	457,092	52.2%	418,563	47.8%	0	0.0%	875,655
Oct-11	645,647	53.3%	565,699	46.7%	0	0.0%	1,211,346
Nov-11	1,086,240	60.6%	706,235	39.4%	0	0.0%	1,792,476
Dec-11	1,886,567	68.3%	875,610	31.7%	0	0.0%	2,762,176
Total	**13,315,672**	**64.3%**	**7,408,392**	**35.7%**	**0**	**0.0%**	**20,724,065**

Note: Purchased gas volumes (Mcf) reported herein reflect specific purchase volumes and do not match sales volumes reported on the revenue accrual method because of cycle billing differences. After adjusting for unbilled revenue estimates, the resulting Lost and Unaccounted for volumes for the Louisiana division in 2011 was approximately (2.14%). Subsequent to December 31, 2011, these estimates were actualized in the normal course of accounting. Had the actualized unbilled estimate been used, the Lost and Unaccounted for volumes would have approximated 1.07%.

RECEIVED
STATE OF COLORADO
PUBLIC UTILITIES COMM
2012 MAR 30 PM 1:26

FERC FORM NO 2:
ANNUAL REPORT OF MAJOR NATURAL GAS UTILITIES

IDENTIFICATION		
01 Exact Legal Name of Respondent Atmos Energy Corporation		Year/Period of Report Dec. 31, 2011
03 Previous Name and Date of Change (If name changed during year)		
04 Address of Principal Office at End of Year (Street, City, State, Zip Code) 5430 LBJ Freeway, Suite 160, Dallas, TX 75240		
05 Name of Contact Person Ryan Ginty	06 Title of Contact Person Director of Financial Reporting	
07 Address of Contact Person (Street, City, State, Zip Code) P.O. Box 650205, Dallas, Texas 75265-0205		
08 Telephone of Contact Person, Including Area Code (972) 934-9227	This Report is: (1) [x] An Original (2) [ ] A Resubmission	10 Date of Report (Mo, Da, Yr)
ANNUAL CORPORATE OFFICER CERTIFICATION		
The undersigned officer certifies that: I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.		
11 Name Christopher T. Forsythe	12 Title Vice President and Controller of Atmos Energy Corporation	
13 Signature Christopher T. Forsythe		14 Date Signed (Mo,Da,Yr) 3/26/2012
Title 18, U.S.C. 1001, makes it a crime for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.		

NOTE: This report reflects the operations of Atmos Energy Corporation's regulated natural gas distribution utility operating divisions: Atmos Energy West Texas (TX), Atmos Energy Colorado-Kansas (CO, KS, MO), Atmos Energy Louisiana (LA), Atmos Energy Kentucky/Mid-States (GA, IL, IA, KY, MO, TN, VA), Atmos Energy Mississippi (MS) and Atmos Energy Mid-Tex (TX). This report also includes the regulated pipeline operations of our Atmos Pipeline - Texas division. These regulated operating divisions do not have separate capital structures. Please refer to the enclosed Atmos Energy Annual Report to Shareholders for further information concerning Atmos Energy Corporation's consolidated operations and activities. Classifications and allocations included herein are made for financial reporting purposes and may not be applicable for ratemaking or other purposes.

Deborah D Littleton

Deborah D. Littleton
Notary Public
State of Texas
Comm. Exp. 5-12-2014

COLORADO ONLY

Name of Respondent	This Report Is:		Date of Report	Year of Report
	(1)	X An Original	(Mo, Da, Yr)	
ATMOS ENERGY CORPORATION	(2)	A Resubmission		Dec. 31, 2011

GAS OPERATING REVENUES (ACCOUNT 400)

1. Report below natural gas operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
4. Report quantities of natural gas sold in Mcf (14.73 psia at 60F). If billings are on a therm basis, give the Btu contents of the gas sold and the sales converted to Mcf.
5. If increases or decreases from previous year (columns (c), (e) and (g)), are not derived from previously

Line No.	Title of Account (a)	OPERATING REVENUES Amount for Year (b)	Amount for Previous Year (c)
1	GAS SERVICE REVENUES		
2	480 Residential Sales	61,418,913	56,601,713
3	481 Commercial & Industrial Sales		
4	Small (or Comm.) (See Instr. 6)	26,800,173	24,327,509
5	Large (or Ind.) (See Instr. 6)	43,074	38,948
6	482 Other Sales to Public Authorities	7,205,646	6,702,157
7	484 Interdepartmental Sales		
8	TOTAL Sales to Ultimate Consumers	95,467,806	87,670,327
9	483 Sales for Resale		
10	TOTAL Nat. Gas Service Revenues	95,467,806	87,670,327
11	Revenues from Manufactured Gas		
12	TOTAL Gas Service Revenues	95,467,806	87,670,327
13	OTHER OPERATING REVENUES		
14	485 Intracompany Transfers		
15	487 Forfeited Discounts	39,973	26,397
16	488 Misc. Service Revenues	705,040	716,295
17	489 Rev. from Trans. of Gas of Others	2,547,967	2,446,970
18	490 Sales of Prod. Ext. from Nat. Gas	14,232	20,055
19	491 Rev. from Nat. Gas Proc. by Others		
20	492 Incidental Gasoline and Oil Sales		
21	493 Rent from Gas Property		
22	494 Interdepartmental Rents		
23	495 Other Gas Revenues	-	-
24	TOTAL Other Operating Revenues	3,307,212	3,209,717
25	TOTAL Gas Operating Revenues	98,775,018	90,880,044
26	(Less) 496 Provision for Rate Refunds		
27	TOTAL Gas Operating Revenues Net of Provision for Refunds	98,775,018	90,880,044
28	Dist. Type Sales by States (Incl. Main Line Sales to Resid. and Comm. Custrs.)	88,219,086	80,929,222
29	Main Line Industrial Sales (Incl. Main Line Sales to Pub. Authorities	43,074	38,948
30	Sales for Resale		
31	Other Sales to Pub. Auth. (Local Dist. Only)	7,205,646	6,702,157
32	Interdepartmental Sales		
33	TOTAL (Same as Line 10, Columns (b) and (d))	95,467,806	87,670,327

COLORADO ONLY

Name of Respondent	This Report Is:	Date of Report (Mo,Da,Yr)	Year of Report
ATMOS ENERGY CORPORATION	(1) X An Original (2) A Resubmission		Dec. 31, 2011

GAS OPERATING REVENUES (ACCOUNT 400) (Continued)

reported figures, explain any inconsistencies in a footnote.

6. Commercial and Industrial Sales, Account 481, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 200,000 Mcf per year or approximately 800 Mcf per day of normal requirements. (See Account 481 of the Uniform System of Accounts. Explain basis of classification in a footnote.)

7. See pages 108-109, Important Changes During Year, for important new territory added and important rate increases or decreases.

MCF OF NATURAL GAS SOLD		AVG. NO. OF NAT. GAS CUSTRS. PER MO.		Line No.
Quantity for Year (d)	Quantity for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	
				1
7,542,467	7,279,992	98,880	98,298	2
				3
3,807,246	3,704,864	10,820	10,836	4
6,205	5,606	5	6	5
1,114,996	1,124,108	1,195	1,189	6
				7
12,470,914	12,114,570	110,900	110,329	8
				9
12,470,914	12,114,570	110,900	110,329	10
				11
				12
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				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
11,349,713				28
6,205				29
				30
1,114,996				31
				32
12,470,914				33

A-2011-0222
A- 2011-222
Atmos Energy Corporation

FORM IG -1

FILED WITH
Executive Secretary
March 29, 2012
IOWA UTILITIES BOARD

ANNUAL REPORT

RATE REGULATED GAS UTILITIES

of

Atmos Energy Corporation

Name of Utility

810 Crescent Centre Drive, Suite 600

Address

Franklin,	TN	37067-6226
City	**State**	**Zip Code**

Chris Forsythe

Name of Person Responsible for Report

P. O. Box 650205
Dallas, Tx 75265-0205

Address if not the same as above

972 - 934 - 9227

Telephone Number

For the Year Ended

December 31, 2011

to the

IOWA UTILITIES BOARD

DES MOINES, IOWA

219-0003

Annual Report
Atmos Energy Corporation — For the year ended December 31, 2011

TOTAL PIPELINES

IOWA ONLY

Iowa Only is defined as revenues and expenses for jurisdictional (regulated by the Iowa Utilities Board) and non-jurisdictional (regulated by the Federal Energy Regulatory Commission).

GAS OPERATING REVENUES (Account 400)

1. Report below natural gas operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Natural gas means either natural gas unmixed or any mixture of natural gas and manufactured gas.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the flat rate accounts; except where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of 12 figures at the close of each month.
4. Report quantities of natural gas sold in Mcf (14.73 psia at 60F). If billings are on a therm basis, give the Btu content of the gas sold and the sales converted to Mcf.

Line No.	Title of Account (a)	Operating Revenues Amount for Year (b)	Amount for Previous Year (c)
1.	GAS SERVICE REVENUES		
2.	480 Residential Sales	2,462,511	2,498,092
3.	481 Commercial Industrial Sales		
4.	Small (or Comm.) (See Instr. 6)	1,277,343	1,280,088
5.	Large (or Ind.) (See Instr. 6)	74,201	69,439
6.	482 Other Sales to Public Author.	-	-
7.	484 Interdepartmental Sales	-	-
8.	TOTAL Sales to Ult. Consumers	3,814,055	3,847,619
9.	483 Sales for Resale	-	-
10.	TOTAL Nat. Gas Serv. Revenues	3,814,055	3,847,619
11.	Revenues from Manufactured Gas	-	-
12.	TOTAL Gas Service Revenues	3,814,055	3,847,619
13.	OTHER OPERATING REVENUES		
14.	487 Forfeited Discounts	12,834	12,997
15.	488 Misc. Service Revenues	5,300	3,935
16.	Revenue from Transportation of Gas of Others Small Volume Customers	976	2,020
17.	Revenue from Transportation of Gas of Others Large Volume Customers	691,037	707,274
18.	489 Total Revenue from Transportation of Gas of Others	692,013	709,294
19.	490 Sales of Prod. Ext. from Nat. Gas.	-	-
20.	491 Rev. from Nat. Gas Proc. by Others	-	-
21.	492 Incidental Gasoline and Oil Sales	-	-
22.	493 Rent from Gas Property	-	-
23.	494 Interdepartmental Sales	-	-
24.	495 Other Gas Revenues	11	-
25.	TOTAL Other Operating Revenues	710,158	726,226
26.	TOTAL Gas Operating Revenues	4,524,213	4,573,845

Note: 1) Revenues are net of any refund distribution
2) Refunds total dollar amount

Form IG-1

Annual Report
Atmos Energy Corporation

For the year ended December 31, 2011

TOTAL PIPELINES

IOWA ONLY

Iowa Only is defined as revenues and expenses for jurisdictional (regulated by the Iowa Utilities Board) and non-jurisdictional (regulated by the Federal Energy Regulatory Commission).

GAS OPERATING REVENUES (Account 400)

5. If increases or decreases from previous year (columns (c), (e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
6. Commercial and Industrial Sales, Account 481, may be classified according to the basis of classification (Small or Commerical, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 200,000 Mcf per year or approximately 800 Mcf per day of normal requirements. (See Account 481 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. Pages 301 - 301.1 operating revenues, Mcf sales and number of customers must equal the total of pages 301.2 - 301.7. If pages 301 and 301.1 totals do not equal the sum of pages 301.2 - 301.7, explain any variances in a footnote.

Line No.	MCF of Natural Gas Sold/Transported Quantity for Year (d)	MCF of Natural Gas Sold/Transported Quantity for Previous Year (e)	Average Number of Natural Gas Customers per Month Number for Year (f)	Average Number of Natural Gas Customers per Month Number for Previous Year (g)
1.				
2.	291,811	304,165	3,820	3,799
3.				
4.	182,164	198,783	460	462
5.	13,520	13,262	1	1
6.	-	-	-	-
7.	-	-	-	-
8.	487,495	516,210	4,281	4,262
9.	-	-	-	-
10.	487,495	516,210	4,281	4,262
11.	-	-	-	-
12.	487,495	516,210	4,281	4,262
13.				
14.				
15.				
16.	14,002	13,565	1	1
17.	2,114,308	2,709,835	17	17
18.	2,128,310	2,723,400	18	18
19.	-	-		
20.	-	-		
21.	-	-		
22.	-	-		
23.	-	-		
24.	-	-		
25.	2,128,310	2,723,400		
26.	2,615,805	3,239,610		

Gas Utility Kansas Supplemental

2011 Annual Report

To The
State of Kansas

State Corporation Commission

for the year ending December 31, 2011

Atmos Energy Corporation-Colorado/Kansas Division
(Exact legal name of respondent) (If name was changed during year, show also name and date of change)

1555 Blake Street, Suite 400, Denver, Colorado
(Address of principal business office at the end of the year)

Area Code (303) Telephone 831-5660
Federal 1D Number 75-1743247
Gross operating revenues derived from Kansas intrastate operations $ 117,664,225

KANSAS CORPORATION COMMISSION
MAR 30 2012
UTILITIES DIVISION

GAS OPERATING REVENUES (Account 400) KANSAS ONLY

1. Report below the amount of operating revenues for the year for each prescribed account and the amount of increase or decrease over the preceding year. If any Kansas revenues below are the results of allocation, explain basis of allocation. If space below is insufficient, attach insert.

2. If increases and decreases are not derived from previously report figures, explain any inconsistencies.

3. Number of customers should be reported on the basis of number of meters, plus number of flat rate accounts, except where separated meter readings are added for billing purposes, one customer shall be counted for each group of meters so added. The average number of customers means the average of the 12 figures at the close of each month. If the customer count in the residential service classification includes customers counted more than once because of special services, such as water heating, etc., indicate in a footnote the number of such duplicate customers included in the classification.

4. Unmetered sales should be included below. The details of such sales should be given in a footnote.

5. Classification of Commercial and Industrial Sales, Account 481, according to Small (or Commercial) and Large (for Industrial) may be according to the basis of classification regularly used by the respondent if such basis of classification is not greater generally than 1000 MCF of demand. See Account 481 of the Uniform System of Accounts. Explain basis of classification.

Line No.	Account No.	Account (a)	OPERATING REVENUE Amount For Year (b)	OPERATING REVENUE Incr. or Decr. From preceding year (c)	MCF OF GAS SOLD Amount For Year (d)	MCF OF GAS SOLD Incr. or Decr. From preceding year (e)	AVERAGE NO. OF CUSTOMERS PER MO. Amount For Year (f)	AVERAGE NO. OF CUSTOMERS PER MO. Incr. or Decr. From preceding year* (g)
		GAS SERVICE REVENUES:						
1.	480	Residential sales	81,805,332	(6,301,521)	9,920,783	(195,127)	117,932	151
2.	481	Commercial and industrial sales	0	0	0	0	0	0
3.		Small (or commercial) see instr. 5	22,463,304	(1,961,276)	3,016,691	(12,354)	9,359	(5)
4.		Large (or industrial) see instr. 5	6,554,665	1,566,519	1,053,178	235,248	361	2
5.	482	Other sales to public authorities	1,951,252	(240,220)	279,982	(13,932)	555	555
6.	483	Sales for resale	0	0	0	0	0	0
7.	484	Interdepartmental sales	0	0	0	0	0	0
8.	485	Intracompany transfers	0	0	0	0	0	0
7.		Total Sales to Ultimate Consumers	112,774,553	(6,936,498)	14,270,634	13,835	128,207	703
8.		Sales for resale	0	0	0	0	0	0
9.		Total Gas Sales Revenue	112,774,553	(6,936,498)	14,270,634	13,835	128,207	703
		OTHER GAS REVENUES:						
10.	487	Forfeited discounts	344,284	(29,631)	See Footnote		See Footnote	
11.	488	Miscellaneous Service revenues	91,827	(3,388)	See Footnote		See Footnote	
12.		Revenues from transportation of gas of others through -						
13.	489.1	Gathering facilities	0	0	0	0	0	0
14.	489.2	Transmission facilities	0	0	0	0	0	0
15.	489.3	Distribution facilities	3,720,562	134,972	6,242,577	(249,427)	377	8
16.	489.4	Revenues from storage gas of others	0	0	0	0	0	0
17.		Total Revenue from Transportation	3,720,562	134,972	6,242,577	(249,427)	377	8
18.	490	Sales of products extracted from natural gas	0	0	* Show decreases in parenthesis()			
19.	491	Revenue from natural gas processed by others	0	0				
20.	492	Incidental gasoline & oil sales	0	0	# Pressure base:		1465 (p.s.i.a.)	
21.	493	Rent from gas property	0	0				
22.	494	Interdepartmental rents	0	0				
23.	495	Other gas revenues	732,999	324,977	@ 60F			
24.	496	Provision for rate refunds	0	0	Btu content per ft.:			
25.		Total Other Operating Gas Revenues	4,889,672	426,930				
26.		Total Gas Operating Revenues	117,664,225	(6,509,568)				
27.		Sales of Natural gas by communities	104,268,636	(8,262,797)				
28.		Mainline industrial sales of natural gas	6,554,665	1,566,519				
29.		Sales to public authorities	1,951,252	(240,220)				
30.		Total Gas Service Revenues (line 9 + line 17)	116,495,115	(6,801,526)				

Footnote: Forfeited discounts and miscellaneous service revenues do not have associated volumes or customers. Miscellaneous service revenues relate to fees for services performed.

THIS FILING IS	
Item 1: ☐ An Initial (Original) Submission	OR ☐ Resubmission No. ____

Form 2 Approved
OMB No.1902-0028
(Expires 10/31/2014)

Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

FERC FINANCIAL REPORT
FERC FORM No. 2: Annual Report of Major Natural Gas Companies and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Natural Gas Act, Sections 10(a), and 16 and 18 CFR Parts 260.1 and 260.300. Failure to report may result in criminal fines, civil penalties, and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of a confidential nature.

Exact Legal Name of Respondent (Company)	Year/Period of Report
Atmos Energy Corporation	End of 2011

GEORGIA ONLY

Name of Respondent	This Report Is:			Date of Report (Mo,Da,Yr)	Year of Report
ATMOS ENERGY CORPORATION	(1)	X	An Original		Dec. 31, 2011
	(2)		A Resubmission		

GAS OPERATING REVENUES (ACCOUNT 400) (Continued)

reported figures, explain any inconsistencies in a footnote.

6. Commercial and Industrial Sales, Account 481, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 200,000 Mcf per year or approximately 800 Mcf per day of normal requirements. (See Account 481 of the Uniform System of Accounts. Explain basis of classification in a footnote.)

7. See pages 108-109, Important Changes During Year, for important new territory added and important rate increases or decreases.

MCF OF NATURAL GAS SOLD		AVG. NO. OF NAT. GAS CUSTRS. PER MO.		Line No.
Quantity for Year (d)	Quantity for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	
				1
2,728,643	3,314,097	55,315	55,818	2
				3
1,447,459	1,594,333	4,554	4,633	4
1,467,072	1,474,959	75	84	5
64,981	72,557	38	39	6
				7
5,708,155	6,455,946	59,982	60,574	8
				9
5,708,155	6,455,946	59,982	60,574	10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
4,176,102				28
				29
1,467,072				
				30
64,981				31
				32
5,708,155				33

GEORGIA ONLY

Name of Respondent	This Report Is:		Date of Report	Year of Report
	(1)	X An Original	(Mo, Da, Yr)	
ATMOS ENERGY CORPORATION	(2)	A Resubmission		Dec. 31, 2011

GAS OPERATING REVENUES (ACCOUNT 400)

1. Report below natural gas operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
4. Report quantities of natural gas sold in Mcf (14.73 psia at 60F). If billings are on a therm basis, give the Btu contents of the gas sold and the sales converted to Mcf.
5. If increases or decreases from previous year (columns (c), (e) and (g)), are not derived from previously

Line No.	Title of Account	OPERATING REVENUES	
		Amount for Year	Amount for Previous Year
	(a)	(b)	(c)
1	GAS SERVICE REVENUES		
2	480 Residential Sales	35,881,923	33,468,346
3	481 Commercial & Industrial Sales		
4	Small (or Comm.) (See Instr. 6)	13,459,336	11,818,323
5	Large (or Ind.) (See Instr. 6)	10,346,947	8,547,584
6	482 Other Sales to Public Authorities	490,305	458,412
7	484 Interdepartmental Sales		
8	TOTAL Sales to Ultimate Consumers	60,178,511	54,292,665
9	483 Sales for Resale		
10	TOTAL Nat. Gas Service Revenues	60,178,511	54,292,665
11	Revenues from Manufactured Gas		
12	TOTAL Gas Service Revenues	60,178,511	54,292,665
13	OTHER OPERATING REVENUES		
14	485 Intracompany Transfers		
15	487 Forfeited Discounts	240,506	223,297
16	488 Misc. Service Revenues	490,994	500,683
17	489 Rev. from Trans. of Gas of Others	2,262,544	2,044,863
18	490 Sales of Prod. Ext. from Nat. Gas		
19	491 Rev. from Nat. Gas Proc. by Others		
20	492 Incidental Gasoline and Oil Sales		
21	493 Rent from Gas Property		
22	494 Interdepartmental Rents		
23	495 Other Gas Revenues	(830,827)	2,765,625
24	TOTAL Other Operating Revenues	2,163,217	5,534,468
25	TOTAL Gas Operating Revenues	62,341,728	59,827,133
26	(Less) 496 Provision for Rate Refunds		
27	TOTAL Gas Operating Revenues Net of Provision for Refunds	62,341,728	
28	Dist. Type Sales by States (Incl. Main Line Sales to Resid. and Comm. Custrs.)	49,341,259	
29	Main Line Industrial Sales (Incl. Main Line Sales to Pub. Authorities	10,346,947	
30	Sales for Resale		
31	Other Sales to Pub. Auth. (Local Dist. Only)	490,305	
32	Interdepartmental Sales		
33	TOTAL (Same as Line 10, Columns (b) and (d))	60,178,511	

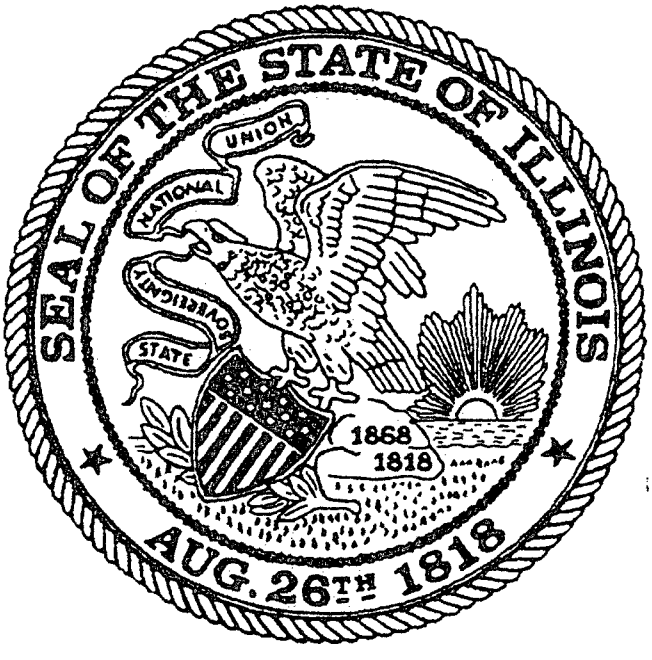
2

FORM 21 ILCC

ANNUAL REPORT OF ELECTRIC UTILITIES LICENSEES AND/OR NATURAL GAS UTILITIES

TO THE

ILLINOIS COMMERCE COMMISSION



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ILLINOIS COMMERCE COMMISSION
CHIEF CLERK'S OFFICE

Exact Legal Name of Respondent (Company)	Year of Report
Atmos Energy Corporation	**December 31, 2011**

This state agency is requesting disclosure of information that is necessary to accomplish the statutory purpose as outlined in Section 5-109 of the Public Utilities Act [220 ILCS 5/5-109]. Disclosure of this information is REQUIRED. Failure to provide any information could result in a fine of $100 per day under Section 5-109 of the Public Utilities Act.

Name of Respondent	This Report Is:	Date of Report (Mo., Day, Yr.)	Year of Report
Atmos Energy Corporation	(1) X An Original (2) A Resubmission		31-Dec-11

ILLINOIS GAS NET OPERATING REVENUES

Instructions: Report the amount derived from or incurred in providing utility services in Illinois.

Line No.	Title of Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	**GAS SERVICE REVENUES**		
2	(480) Residential Sales	$ 13,926,450	$ 14,281,316
3	(481) Commercial and Industrial Sales		
4	Small (or Commercial)	6,507,055	6,146,038
5	Large (or Industrial)	554,699	535,009
6	(482) Other Sales to Public Authorities	229,019	231,753
7	TOTAL Sales to Ultimate Consumers (lines 2-6)	21,217,223	21,194,116
8	(483) Sales for Resale	-	-
9	(484) Interdepartmental Sales	-	-
10			
11			
12	TOTAL Gas Service Revenues (lines 7-9)	21,217,223	21,194,116
13	**OTHER OPERATING REVENUES**		
14	(485) Intracompany Transfers		
15	(487) Forfeited Discounts	71,872	63,024
16	(488) Miscellaneous Service Revenues	27,867	31,941
17	(489.1) Rev. from Trans. of Gas of others through gathering facilities	-	-
18	(489.2) Rev. from Trans. of Gas of others through transmission facilities	368,182	390,267
19	(489.3) Rev. from Trans. of Gas of others through distribution facilities	-	-
20	(489.4) Rev. from storing gas of others	-	-
21	(490) Sales of Prod. Ext. from Natural Gas	-	-
22	(491) Rev. from Natural Gas Proc. by Others	-	-
23	(492) Incidental Gasoline and Oil Sales	-	-
24	(493) Rent from Gas Property	-	-
25	(494) Interdepartmental Rents	-	-
26	(495) Other Gas Revenues	-	-
27	TOTAL Other Operating Revenues (Total of lines 14-26)	467,921	485,232
28	TOTAL Gas Operating Revenues (Total of lines 12 plus 27)	$ 21,685,144	$ 21,679,348
29	(Less) (496) Provision for Rate Refunds	-	-
30	TOTAL Gas Operating Revenues Net of Provision for Refunds (lines 28-29)	$ 21,685,144	$ 21,679,348
31	Dist. Type Sales by States (Incl. Main Line Sales to Resid. and Comm. Cust.)	20,988,204	20,962,363
32	Main Line Industrial Sales (Incl. Main Line Sales to Pub. Authorities)	-	-
33	Sales for Resale	-	-
34	Other Sales to Pub. Auth. (Local Dist. Only)	229,019	231,753
35	Interdepartmental Sales	-	-
36	TOTAL (Same as Line 12, columns (b) and (c))	$ 21,217,223	$ 21,194,116

Name of Respondent	This Report Is:	Date of Report (Mo., Day, Yr.)	Year of Report
Atmos Energy Corporation	(1) X An Original (2) A Resubmission		31-Dec-11

ILLINOIS GAS NET OPERATING REVENUES (Continued)

THERMS OF NATURAL GAS SOLD		AVERAGE NO. OF NAT. GAS CUSTOMERS PER MO.		Line No.
Current Year (d)	Prior Year (e)	Current Year (f)	Prior Year (g)	
				1
14,527,580	15,480,640	20,123	20,276	2
				3
7,684,430	7,509,200	2,085	2,071	4
733,070	762,890	7	7	5
237,980	261,830	322	259	6
23,183,060	24,014,560	22,537	22,613	7
-	-	-	-	8
-	-	-	-	9
				10
				11
23,183,060	24,014,560	22,537	22,613	12
				13

Quantity of Natural Gas Transported		Average No. of Transport Customers Per Month		
Current Year	Prior Year	Current Year	Prior Year	
-	-	-	-	17
7,462,340	7,430,380	7	7	18
-	-	-	-	19

ANNUAL FINANCIAL AND OPERATING REPORT

OF

ATMOS ENERGY-KENTUCKY/MID-STATES

A DIVISION OF ATMOS ENERGY CORPORATION

TO THE

State Corporation Commission

OF THE

COMMONWEALTH OF VIRGINIA

	Date	By Whom
Acknowledged	3-30-12	YRS
Computations		
Checked		
Letter of Exceptions		
Reply to Exceptions		
Copied		

FOR THE YEAR ENDED DECEMBER 31, 2011

Name of Respondent	This Report Is:		Date of Report	Year of Report
	(1)	X An Original	(Mo, Da, Yr)	
ATMOS ENERGY CORPORATION	(2)	A Resubmission		Dec. 31, 2011

GAS OPERATING REVENUES (ACCOUNT 400)

1. Report below natural gas operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
3.. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
4. Report quantities of natural gas sold in Mcf (14.73 psia at 60F). If billings are on a therm basis, give the Btu contents of the gas sold and the sales converted to Mcf.
5. If increases or decreases from previous year (columns (c), (e) and (g)), are not derived from previously

Line No.	Title of Account	OPERATING REVENUES	
		Amount for Year	Amount for Previous Year
	(a)	(b)	(c)
1	GAS SERVICE REVENUES		
2	480 Residential Sales	1,613,684,060	1,777,521,641
3	481 Commercial & Industrial Sales		
4	Small (or Comm.) (See Instr. 6)	722,732,687	785,624,067
5	Large (or Ind.) (See Instr. 6)	114,572,743	115,764,687
6	482 Other Sales to Public Authorities	58,009,508	61,380,747
7	484 Interdepartmental Sales	-	-
8	TOTAL Sales to Ultimate Consumers	2,508,998,998	2,740,291,142
9	483 Sales for Resale	3,038,295	2,651,704
10	TOTAL Nat. Gas Service Revenues	2,512,037,293	2,742,942,846
11	Revenues from Manufactured Gas	-	-
12	TOTAL Gas Service Revenues	2,512,037,293	2,742,942,846
13	OTHER OPERATING REVENUES		
14	485 Intracompany Transfers	-	-
15	487 Forfeited Discounts	5,236,868	5,673,188
16	488 Misc. Service Revenues	21,125,887	22,288,347
17	489 Rev. from Trans. of Gas of Others	143,416,106	154,647,316
18	490 Sales of Prod. Ext. from Nat. Gas	14,232	20,055
19	491 Rev. from Nat. Gas Proc. by Others	-	-
20	492 Incidental Gasoline and Oil Sales	327,771	414,767
21	493 Rent from Gas Property	205,207	204,134
22	494 Interdepartmental Rents	-	-
23	495 Other Gas Revenues	5,689,723	12,048,954
24	TOTAL Other Operating Revenues	176,015,794	195,296,761
25	TOTAL Gas Operating Revenues	2,688,053,087	2,938,239,607
26	(Less) 496 Provision for Rate Refunds	-	-
27	TOTAL Gas Operating Revenues Net of Provision for Refunds	2,688,053,087	
28	Dist. Type Sales by States (Incl. Main Line Sales to Resid. and Comm. Custrs.)	2,336,416,747	
29	Main Line Industrial Sales (Incl. Main Line Sales to Pub. Authorities	114,572,743	
30	Sales for Resale	3,038,295	
31	Other Sales to Pub. Auth. (Local Dist. Only)	58,009,508	
32	Interdepartmental Sales		
33	TOTAL (Same as Line 10, Columns (b) and (d))	2,512,037,293	

Name of Respondent	This Report Is:		Date of Report (Mo,Da,Yr)	Year of Report
ATMOS ENERGY CORPORATION	(1) X An Original (2) A Resubmission			Dec. 31, 2011

GAS OPERATING REVENUES (ACCOUNT 400) (Continued)

reported figures, explain any inconsistencies in a footnote.

6. Commercial and Industrial Sales, Account 481, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 200,000 Mcf per year or approximately 800 Mcf per day of normal requirements. (See Account 481 of the Uniform System of Accounts. Explain basis of classification in a footnote.)

7. See pages 108-109, Important Changes During Year, for important new territory added and important rate increases or decreases.

MCF OF NATURAL GAS SOLD		AVG. NO. OF NAT. GAS CUSTRS. PER MO.		Line No.
Quantity for Year (d)	Quantity for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	
				1
166,071,967	181,701,511	2,889,791	2,886,475	2
				3
94,688,376	99,432,632	258,285	257,843	4
20,546,370	19,826,918	2,139	2,173	5
8,492,547	8,589,330	9,123	9,046	6
-	-			7
289,799,260	309,550,391	3,159,338	3,155,537	8
657,827	552,397			9
290,457,087	310,102,788	3,159,338	3,155,537	10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
260,760,343				28
20,546,370				29
657,827				30
8,492,547				31
				32
290,457,087				33

THIS FILING IS	
Item 1: ☐ An Initial (Original) Submission	OR ☐ Resubmission No. ____

Form 2 Approved
OMB No.1902-0028
(Expires 10/31/2014)

Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

FERC FINANCIAL REPORT
FERC FORM No. 2: Annual Report of Major Natural Gas Companies and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Natural Gas Act, Sections 10(a), and 16 and 18 CFR Parts 260.1 and 260.300. Failure to report may result in criminal fines, civil penalties, and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of a confidential nature.

Exact Legal Name of Respondent (Company)	Year/Period of Report
Atmos Energy Corporation	End of 2011

Name of Respondent	This Report Is:			Date of Report	Year of Report
	(1)	X	An Original	(Mo, Da, Yr)	
ATMOS ENERGY CORPORATION	(2)		A Resubmission		Dec. 31, 2011

GAS OPERATING REVENUES (ACCOUNT 400) - TENNESSEE ONLY

1. Report below natural gas operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
4. Report quantities of natural gas sold in Mcf (14.73 psia at 60F). If billings are on a therm basis, give the Btu contents of the gas sold and the sales converted to Mcf.
5. If increases or decreases from previous year (columns (c), (e) and (g)), are not derived from previously

Line No.	Title of Account	OPERATING REVENUES	
		Amount for Year	Amount for Previous Year
	(a)	(b)	(c)
1	GAS SERVICE REVENUES		
2	480 Residential Sales	70,205,979	74,863,654
3	481 Commercial & Industrial Sales		
4	Small (or Comm.) (See Instr. 6)	45,306,287	48,840,031
5	Large (or Ind.) (See Instr. 6)	9,045,664	9,198,923
6	482 Other Sales to Public Authorities	500,528	525,437
7	484 Interdepartmental Sales		
8	TOTAL Sales to Ultimate Consumers	125,058,458	133,428,045
9	483 Sales for Resale		
10	TOTAL Nat. Gas Service Revenues	125,058,458	133,428,045
11	Revenues from Manufactured Gas		
12	TOTAL Gas Service Revenues	125,058,458	133,428,045
13	OTHER OPERATING REVENUES		
14	485 Intracompany Transfers		
15	487 Forfeited Discounts	887,657	943,747
16	488 Misc. Service Revenues	460,896	492,274
17	489 Rev. from Trans. of Gas of Others	7,056,830	7,161,220
18	490 Sales of Prod. Ext. from Nat. Gas		
19	491 Rev. from Nat. Gas Proc. by Others		
20	492 Incidental Gasoline and Oil Sales		
21	493 Rent from Gas Property		
22	494 Interdepartmental Rents		
23	495 Other Gas Revenues	(1,257)	(9,848)
24	TOTAL Other Operating Revenues	8,404,126	8,587,393
25	TOTAL Gas Operating Revenues	133,462,584	142,015,438
26	(Less) 496 Provision for Rate Refunds		
27	TOTAL Gas Operating Revenues Net of Provision for Refunds	133,462,584	
28	Dist. Type Sales by States (Incl. Main Line Sales to Resid. and Comm. Custrs.)	115,512,266	
29	Main Line Industrial Sales (Incl. Main Line Sales to Pub. Authorities	9,045,664	
30	Sales for Resale		
31	Other Sales to Pub. Auth. (Local Dist. Only)	500,528	
32	Interdepartmental Sales		
33	TOTAL (Same as Line 10, Columns (b) and (d))	125,058,458	

Name of Respondent	This Report Is:		Date of Report	Year of Report
	(1)	X An Original	(Mo,Da,Yr)	
ATMOS ENERGY CORPORATION	(2)	A Resubmission		Dec. 31, 2011

GAS OPERATING REVENUES (ACCOUNT 400) - TENNESSEE ONLY (Continued)

reported figures, explain any inconsistencies in a footnote.

6. Commercial and Industrial Sales, Account 481, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 200,000 Mcf per year or approximately 800 Mcf per day of normal requirements. (See Account 481 of the Uniform System of Accounts. Explain basis of classification in a footnote.)

7. See pages 108-109, Important Changes During Year, for important new territory added and important rate increases or decreases.

MCF OF NATURAL GAS SOLD		AVG. NO. OF NAT. GAS CUSTRS. PER MO.		Line No.
Quantity for Year (d)	Quantity for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	
				1
7,221,810	7,887,180	114,039	113,351	2
				3
4,901,700	5,407,630	15,511	15,273	4
1,298,807	1,313,693	362	363	5
63,416	67,570	483	486	6
				7
13,485,733	14,676,073	130,395	129,473	8
				9
13,485,733	14,676,073	130,395	129,473	10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
12,123,510				28
1,298,807				29
				30
63,416				31
				32
13,485,733				33

THIS FILING IS	
Item 1: ☐ An Initial (Original) Submission	OR ☐ Resubmission No. ____

Form 2 Approved
OMB No.1902-0028
(Expires 10/31/2014)

Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

FERC FINANCIAL REPORT
FERC FORM No. 2: Annual Report of Major Natural Gas Companies and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Natural Gas Act, Sections 10(a), and 16 and 18 CFR Parts 260.1 and 260.300. Failure to report may result in criminal fines, civil penalties, and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of a confidential nature.

Exact Legal Name of Respondent (Company)	Year/Period of Report
Atmos Energy Corporation	End of 2011

Annual Report of Atmos Energy Corporation

For the calendar year of January 1 - December 31, 2011

REVENUE BY SCHEDULES

Atmos Energy Corporation

Line No.	Rate Class and Line Items	Operating Revenues Current Year	Operating Revenues Previous Year	MCF of Natural Gas Sold Current Year	MCF of Natural Gas Sold Previous Year	Average No. of Natural Gas Customers Current Year	Average No. of Natural Gas Customers Previous Year
1	Residential Firm Service	$ 32,992,366	$ 28,245,667	3,276,458	3,406,545	48,900	49,285
2	Small Firm General Service	6,392,428	4,356,503	799,474	614,311	5,968	5,440
3	Medium Firm General Service	8,331,946	8,519,154	882,687	1,068,702	792	1,343
4	Large Firm General Service	2,652,272	1,800,501	397,247	349,733	31	36
5	Interruptible Large Volume Gas Service	885,113	729,083	130,755	138,357	7	8
6	Negotiated Gas Sales Service	-	-	0	0	0	0
7	Economic Development Gas Service	-	-	0	0	0	0
8	Transportation Service	1,885,289	1,445,932	3,210,363	2,977,426	192	206
9	Other Sales to Public Authorities	-	-	0	0		
10	Interdepartmental Sales	-	-	0	0	0	0
11							
12							
13	Total to Ultimate Consumers	$ 53,139,414	$ 45,096,840	8,696,983	8,555,074	55,890	56,318

	Rate Class and Line Items	Average Number of Natural Gas Customers Per Month					
		January	February	March	April	May	June
14	Residential Firm Service	49,855	50,086	50,305	50,140	49,540	48,846
15	Small Firm General Service	5,998	6,020	6,021	6,011	5,986	5,968
16	Medium Firm General Service	817	809	796	794	790	786
17	Large Firm General Service	31	31	31	31	32	33
18	Interruptible Large Volume Gas Service	8	8	8	8	8	8
19	Negotiated Gas Sales Service	0	0	0	0	0	0
20	Economic Development Gas Service	0	0	0	0	0	0
21	Transportation Service	190	194	190	190	191	191
22	Other Sales to Public Authorities	0	0	0	0	0	0
23	Interdepartmental Sales	0	0	0	0	0	0
24							
25							
26	Total to Ultimate Consumers	56,898	57,147	57,351	57,173	56,546	55,830

	Rate Class and Line Items	Average Number of Natural Gas Customers Per Month					
		July	August	September	October	November	December
27	Residential Firm Service	48,229	47,701	47,589	47,748	48,103	48,881
28	Small Firm General Service	5,946	5,914	5,897	5,894	5,937	6,002
29	Medium Firm General Service	785	783	788	796	790	787
30	Large Firm General Service	32	30	31	32	31	32
31	Interruptible Large Volume Gas Service	8	7	6	6	6	7
32	Negotiated Gas Sales Service	0	0	0	0	0	0
33	Economic Development Gas Service	0	0	0	0	0	0
34	Transportation Service	191	192	192	192	193	193
35	Other Sales to Public Authorities	0	0	0	0	0	0
36	Interdepartmental Sales	0	0	0	0	0	0
37							
38							
39	Total to Ultimate Consumers	55,189	54,625	54,502	54,667	55,060	55,901

The average number of customers for the month should equal the number of customers at the beginning of the month added to the number of customers at the end of the month divided by 2.

ANNUAL FINANCIAL AND OPERATING REPORT

OF

ATMOS ENERGY-KENTUCKY/MID-STATES

A DIVISION OF ATMOS ENERGY CORPORATION

TO THE

State Corporation Commission

OF THE

COMMONWEALTH OF VIRGINIA

	Date	By Whom
Acknowledged	3-30-12	YRS
Computations		
Checked		
Letter of Exceptions		
Reply to Exceptions		
Copied		

FOR THE YEAR ENDED DECEMBER 31, 2011

ANNUAL FINANCIAL AND OPERATING REPORT

OF

ATMOS ENERGY-KENTUCKY/MID-STATES

A DIVISION OF ATMOS ENERGY CORPORATION

TO THE

State Corporation Commission

OF THE

COMMONWEALTH OF VIRGINIA

FOR THE YEAR ENDED DECEMBER 31, 2011

VIRGINIA ONLY

Name of Respondent	This Report Is:		Date of Report (Mo,Da,Yr)	Year of Report
ATMOS ENERGY CORPORATION	(1) X An Original (2) A Resubmission			Dec. 31, 2011

GAS OPERATING REVENUES (ACCOUNT 400) (Continued)

reported figures, explain any inconsistencies in a footnote.

6. Commercial and Industrial Sales, Account 481, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 200,000 Mcf per year or approximately 800 Mcf per day of normal requirements. (See Account 481 of the Uniform System of Accounts. Explain basis of classification in a footnote.)

7. See pages 108-109, Important Changes During Year, for important new territory added and important rate increases or decreases.

MCF OF NATURAL GAS SOLD		AVG. NO. OF NAT. GAS CUSTRS. PER MO.		Line No.
Quantity for Year (d)	Quantity for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	
				1
1,076,825	1,206,495	17,663	17,625	2
				3
1,841,870	2,066,986	4,315	4,291	4
1,860,684	2,140,908	78	83	5
87,087	88,975	317	309	6
-	-	-	-	7
4,866,466	5,503,364	22,373	22,308	8
-	-	-	-	9
4,866,466	5,503,364	22,373	22,308	10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
2,918,695				28
1,947,771				29
				30
-				31
				32
4,866,466				33

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LACLEDE GROUP INC

FORM 10-K
(Annual Report)

Filed 11/21/11 for the Period Ending 09/30/11

Address	720 OLIVE ST ST LOUIS, MO 63101
Telephone	3143420500
CIK	0001126956
Symbol	LG
SIC Code	4924 - Natural Gas Distribution
Industry	Natural Gas Utilities
Sector	Utilities
Fiscal Year	09/30

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RISKS THAT RELATE TO THE REGULATED GAS DISTRIBUTION SEGMENT

Regulation of the Utility business may impact rates it is able to charge, costs, and profitability.

The Missouri Public Service Commission (MoPSC or Commission) regulates many aspects of the Utility's distribution operations, including construction and maintenance of facilities, operations, safety, the rates that the Utility may charge customers, the terms of service to its customers, transactions with its affiliates, and the rate of return that it is allowed to realize; as well as the accounting treatment for certain aspects of its operations. For further discussion of these accounting matters, see Critical Accounting Policies pertaining to Laclede Gas, beginning on page 33. Laclede Gas' ability to obtain and timely implement rate increases and rate supplements to maintain the current rate of return depends upon regulatory discretion. There can be no assurance that it will be able to obtain rate increases or rate supplements or continue earning the current authorized rates of return.

Laclede Gas' liquidity may be adversely affected by delays in recovery of its costs, due to regulation.

In the normal course of business, there may be a lag between when the Utility incurs increases in certain of its costs and the time in which those costs are considered for recovery in the ratemaking process. Cash requirements for increased operating costs, increased funding levels of defined benefit pension and postretirement costs, capital expenditures, and other increases in the costs of doing business may require outlays of cash prior to the authorization of increases in rates charged to customers, as approved by the MoPSC. Accordingly, the Utility's liquidity may be adversely impacted to the extent higher costs are not timely recovered from its customers.

Laclede Gas' ability to meet its customers' natural gas requirements may be impaired if contracted gas supplies, interstate pipeline and/or storage services are not available or delivered in a timely manner.

In order to meet its customers' annual and seasonal natural gas demands, the Utility must obtain sufficient supplies, interstate pipeline capacity, and storage capacity. If it is unable to obtain these, either from its suppliers' inability to deliver the contracted commodity or the inability to secure replacement quantities, Laclede Gas' financial condition and results of operations may be adversely impacted.

Laclede Gas' liquidity and, in certain circumstances, its results of operations may be adversely affected by the cost of purchasing natural gas during periods in which natural gas prices are rising significantly.

Laclede Gas' tariff rate schedules contain Purchased Gas Adjustment (PGA) Clauses that permit the Utility to file for rate adjustments to recover the cost of purchased gas. Changes in the cost of purchased gas are flowed through to customers and may affect uncollectible amounts and cash flows and can therefore impact the amount of capital resources. Currently, Laclede Gas is allowed to adjust the gas cost component of its rates up to four times each year. The Utility must make a mandatory gas cost adjustment at the beginning of the winter, in November, and during the next twelve months it may make up to three additional discretionary gas cost adjustments, so long as each of these adjustments is separated by at least two months.

The MoPSC typically approves the Utility's PGA changes on an interim basis, subject to refund and the outcome of a subsequent audit and prudence review. Due to such review process, there is a risk of a disallowance of full recovery of these costs. Any material disallowance of purchased gas costs would adversely affect revenues. Increases in the prices the Utility charges for gas may also adversely affect revenues because they could lead customers to reduce usage and cause some customers to have trouble paying the resulting higher bills. These higher prices may increase bad debt expenses and ultimately reduce earnings. Laclede Gas has used short-term borrowings in the past to finance storage inventories and purchased gas costs, and expects to do so in the future. Rapid increases in the price of purchased gas may result in an increase in short-term debt because Laclede Gas must pay suppliers for gas in advance of when its customers pay for that gas.

ITEM 7 . MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

THE LACLEDE GROUP, INC.

INTRODUCTION

This management's discussion analyzes the financial condition and results of operations of The Laclede Group, Inc. (Laclede Group or the Company) and its subsidiaries. It includes management's view of factors that affect its business, explanations of past financial results including changes in earnings and costs from the prior year periods, and their effects on the Company's overall financial condition and liquidity.

The Management's Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the Company's consolidated financial statements and the notes thereto.

RESULTS OF OPERATIONS

Overview

Laclede Group's earnings are primarily derived from the regulated activities of its largest subsidiary, Laclede Gas Company (Laclede Gas or the Utility), Missouri's largest natural gas distribution company. Laclede Gas is regulated by the Missouri Public Service Commission (MoPSC or Commission) and serves the City of St. Louis and parts of ten counties in eastern Missouri. Laclede Gas delivers natural gas to retail customers at rates and in accordance with tariffs authorized by the MoPSC. The Utility's earnings are primarily generated by the sale of heating energy. The Utility's weather mitigation rate design lessens the impact of weather volatility on Laclede Gas' customers during cold winters and stabilizes the Utility's earnings by recovering fixed costs more evenly during the heating season. Due to the seasonal nature of the business of Laclede Gas, Laclede Group's earnings are typically concentrated in the November through April period, which generally corresponds with the heating season.

Laclede Energy Resources, Inc. (LER) is engaged in the marketing of natural gas and related activities on a non-regulated basis. LER markets natural gas to both on-system Utility transportation customers and customers outside of Laclede Gas' traditional service territory, including large retail and wholesale customers. LER's operations and customer base are more subject to fluctuations in market conditions than the Utility.

Other subsidiaries provide less than 10% of consolidated revenues.

In June 2011, the Company's Board of Directors named Ms. Suzanne Sitherwood, age 51, as successor to Mr. Douglas H. Yaeger, who will retire on February 1, 2012. Ms. Sitherwood became President of the Company effective September 1, 2011 and is expected to become Chief Executive Officer effective upon Mr. Yaeger's retirement. In connection with Mr. Yaeger's transition to retirement, Mr. Yaeger relinquished his title of President of the Company on September 1, 2011. On July 28, 2011, the Company's Board of Directors increased the size of the Board from nine to ten and appointed Ms. Sitherwood to the Board effective September 1, 2011.

Based on the nature of the business of the Company and its subsidiaries, as well as current economic conditions, management focuses on the following key variables in evaluating the financial condition and results of operations and managing the business:

Regulated Gas Distribution Segment:

- the Utility's ability to recover the costs of purchasing and distributing natural gas from its customers;
- the impact of weather and other factors, such as customer conservation, on revenues and expenses;
- changes in the regulatory environment at the federal, state, and local levels, as well as decisions by regulators, that impact the Utility's ability to earn its authorized rate of return;
- the Utility's ability to access credit markets and maintain working capital sufficient to meet operating requirements; and,
- the effect of natural gas price volatility on the business.

Non-Regulated Gas Marketing Segment:

- the risks of competition;
- regional and seasonal fluctuations in natural gas prices;
- new national pipeline infrastructure projects;
- credit and/or capital market access;
- counterparty risks;
- the effect of natural gas price volatility on the business; and,
- pursuing additional growth.

Futher information regarding how mangement seeks to manage these key variables is discussed below.

Laclede Gas continues to provide reliable natural gas service at a reasonable cost, while maintaining and building a secure and dependable infrastructure. The Utility's strategy focuses on improving performance and mitigating the impact of weather fluctuations on Laclede Gas' customers while improving the ability to recover its authorized distribution costs and return. The Utility's distribution costs are the essential, primarily fixed, expenditures it must incur to operate and maintain more than 16,000 miles of mains and services comprising its natural gas distribution system and related storage facilities. The Utility's distribution costs include wages and employee benefit costs, depreciation and maintenance expenses, and other regulated utility operating expenses, excluding natural and propane gas expense. Distribution costs are considered in the ratemaking process, and recovery of these types of costs is included in revenues generated through the Utility's tariff rates, as approved by the MoPSC. The settlement of the Utility's rate case in 2010 retained the Utility's weather mitigation rate design that better ensures the recovery of its fixed costs and margins despite variations in sales volumes due to the impacts of weather and other factors that affect customer usage.

The Utility's income from off-system sales and capacity release remains subject to fluctuations in market conditions. The Utility is allowed to retain 15% to 25% of the first $6 million in annual income earned (depending on the level of income earned) and 30% of income exceeding $6 million annually. Some of the factors impacting the level of off-system sales include the availability and cost of the Utility's natural gas supply, the weather in its service area, and the weather in other markets. When Laclede Gas' service area experiences warmer-than-normal weather while other markets experience colder weather or supply constraints, some of the Utility's natural gas supply is available for off-system sales and there may be a demand for such supply in other markets. See the Regulatory and Other Matters section on page 36 of this report for additional information on regulatory issues relative to the Utility.

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NEW JERSEY RESOURCES CORP

FORM 10-K
(Annual Report)

Filed 11/23/11 for the Period Ending 09/30/11

Address	1415 WYCKOFF RD PO BOX 1468 WALL, NJ 07719
Telephone	9089381494
CIK	0000356309
Symbol	NJR
SIC Code	4924 - Natural Gas Distribution
Industry	Natural Gas Utilities
Sector	Utilities
Fiscal Year	09/30

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ITEM 1. BUSINESS (Continued)

Operating Revenues/Throughput

For the fiscal year ended September 30, 2011 , operating revenues and throughput by customer class were as follows:

	Operating Revenues		Throughput	
	(Thousands)		(Bcf) [1]	
Residential	$ 579,038	59%	42.3	24%
Commercial and other	116,043	12	8.3	4
Firm transportation	57,126	6	12.2	7
Total residential and commercial	**752,207**	**77%**	**62.8**	**35%**
Interruptible	7,029	1	8.3	5
Total system	**759,236**	**78%**	**71.1**	**40%**
Incentive programs	212,488	22	107.0	60
Total	**$ 971,724**	**100%**	**178.1**	**100%**

(1) Billion cubic feet.

In fiscal 2011 , no single customer represented more than 10 percent of total NJNG operating revenue.

Seasonality of Gas Revenues

As a result of the heat-sensitive nature of NJNG's residential customer base, therm sales are significantly affected by weather conditions. Specifically, customer demand substantially increases during the winter months when natural gas is used for heating purposes. Weather conditions directly influence the volume of natural gas delivered to customers. The relative measurement of the impact of weather is in degree-days. Degree-day data is used to estimate amounts of energy required to maintain comfortable indoor temperature levels based on each day's average temperature. A degree-day is the measure of the variation in the weather based on the extent to which the average daily temperature falls below 65 degrees Fahrenheit. Each degree of temperature below 65 degrees Fahrenheit is counted as one heating degree-day. Normal heating degree-days are based on a twenty-year average, calculated based upon three reference areas representative of NJNG's service territory.

The CIP, a mechanism authorized by the BPU, stabilizes fluctuations in NJNG's utility gross margin, as a result of variations in weather. In addition, the CIP decouples the link between utility gross margin and customer usage, allowing NJNG to promote energy conservation measures. Recovery of such utility gross margin is subject to additional conditions including an earnings test and an evaluation of Basic Gas Supply Service (BGSS)-related savings achieved. The CIP was initially authorized in October 2006 as a three-year pilot program, however, due to the continuing nature of energy efficiency programs at the state and federal levels in concert with the issuance of the economic stimulus programs, in fiscal 2010 NJNG requested and received approval from the BPU to extend the CIP through September 30, 2013.

For additional information regarding the CIP, see *Item 7. Management's Discussion and Analysis-Natural Gas Distribution Operations* and *Note 3. Regulation* in the accompanying Consolidated Financial Statements.

Gas Supply

Firm Natural Gas Supplies

NJNG's gas supply portfolio consists of long-term (over seven months), winter-term (November through March) and short-term (seven months or less) contracts. In fiscal 2011 , NJNG purchased gas from approximately one hundred suppliers under contracts ranging from one day to one year and purchased over 10 percent of its natural gas from two suppliers, Southwestern Energy Services Company and EQT Energy, LLC. NJNG believes the loss of any one or both of these suppliers would not have a material adverse impact on its results of operations, financial position or cash flows as an adequate number of alternative suppliers exist. NJNG believes that its supply strategy should adequately meet its expected firm load over the next several years.

Firm Transportation and Storage Capacity

In order to take delivery of firm natural gas supplies, which ensures the ability to reliably service its customers, NJNG maintains agreements for firm transportation and storage capacity with several interstate pipeline companies. NJNG receives natural gas at eight citygate stations located in Middlesex, Morris and Passaic counties in New Jersey.

Natural Gas Distribution Segment

Our natural gas distribution segment has approximately 495,000 residential and commercial customers in its service territory. The business is subject to various risks, such as those associated with adverse economic conditions that can negatively impact customer growth, operating and financing costs, fluctuations in commodity prices, which can impact customer usage, customer conservation efforts, certain regulatory actions, and environmental remediation. It is often difficult to predict the impact of trends associated with these risks. NJNG employs certain strategies to manage the challenges it faces, including pursuing customer conversions from other fuel sources and monitoring new construction markets through contact with developers, utilizing incentive programs through BPU-approved mechanisms to reduce gas costs, pursuing rate and other regulatory strategies designed to stabilize and decouple margin, and working actively with consultants and the New Jersey Department of Environmental Protection (NJDEP) to manage expectations related to its obligations associated with NJNG's manufactured gas plant (MGP) sites.

NJNG's operations are managed with the goal of providing safe and reliable service, growing profitably and promoting clean energy programs through several key initiatives including:

- Earning a reasonable rate of return on the investments in its natural gas distribution system, as well as recovery of all prudently incurred costs in order to provide safe and reliable service throughout NJNG's territory;

- Working with the BPU and the New Jersey Division of Rate Counsel (Rate Counsel), on the continuation of the Conservation Incentive Program (CIP). The CIP allows NJNG to promote conservation programs to its customers while maintaining protection of its utility gross margin, which is a non-GAAP financial measure, against potential losses associated with reduced customer usage. CIP usage differences are calculated annually and are recovered one year following the end of the CIP usage year. U tility gross margin is defined as natural gas revenues less natural gas purchases, sales tax, a Transitional Energy Facilities Assessment (TEFA) and regulatory rider expenses. See the *Results of Operations* section of *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* for a further discussion of utility gross margin ;

- Managing its new customer growth rate, which is expected to be approximately 1.4 percent annually over the next two years;

- Generating earnings from various BPU-authorized gross margin-sharing incentive programs;

- Maintaining the integrity of its infrastructure, while working with the BPU to accelerate certain infrastructure projects in an effort to stimulate the local and state economies, while earning an immediate return on investment;

- Coordinating with the BPU on energy efficiency projects; and

- Managing the volatility of wholesale natural gas prices through a hedging program designed to keep customers' Basic Gas Supply Service (BGSS) rates as stable as possible.

Conservation Incentive Program

The CIP allows NJNG to recover utility gross margin variations related to both weather and customer usage subject to certain conditions. An annual review of the CIP must be filed in June, coincident with NJNG's annual BGSS filing. NJNG's filing in June 2010 , included recovery of $12.1 million annually, an increase of $5.2 million , for accrued and estimated CIP amounts through September 30, 2010 . This increase was approved by the BPU to be effective October 1, 2010 . In June 2011 , NJNG filed for a change in the CIP rates, effective October 1, 2011 . The proposed CIP rates result in a 0.8 percent decrease to residential heat customers and a minor increase to all other customers. See *Note 3. Regulation* in the accompanying Consolidated Financial Statements and the *Results of Operations* section of *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* for more information on the impact to utility gross margin.

As of September 30, 2011 , NJNG has $11.4 million in regulatory assets in the Consolidated Balance Sheets related to CIP accrued to be recovered in future periods from customers.

ANNUAL REPORT

OF

NEW JERSEY NATURAL GAS COMPANY

NAME OF RESPONDENT

1415 WYCKOFF ROAD, P.O. BOX 1464, WALL, N.J. 07719

ADDRESS OF RESPONDENT

TO THE

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
44 SOUTH CLINTON AVENUE, 9TH FLOOR
POST OFFICE BOX 350
TRENTON, NEW JERSEY 07102

FOR THE YEAR ENDED DECEMBER 31, 2011

Name of Officer in charge of correspondence

with the Board regarding this report WILLIAM G. FOLEY, TREASURER

Official Title TREASURER **Office Address** 1415 WYCKOFF ROAD

WALL, NJ 07719

Name and Address of Registered Agent _____

NAME OF RESPONDENT New Jersey Natural Gas Company	This Report is: [x] An Original [ ] A Resubmission	Date of Report *April 30, 2012*		Year of Report Dec. 31, 2011

GAS OPERATION REVENUES (Account 400) (Continued)

1. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
2. If increases or decreases from previous year (columns (c), (e) and (g) are not derived from previously reported figures, explain any inconsistencies in a footnote.
3. Commercial and Industrial Sales, Account 481, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 200,000 Mcf per year or approximately 800 Mcf per day of normal requirements. (See Account 481 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
4. Provide a reconciliation of the total amounts on line 20 and the amounts on lines 1,5,6,7, and 8 of page 301 in the area provided for notes.

Line No.	Customer Class	Operating Revenues		Therms of Gas Sold		Avg. No. of Nat. Gas Customers per Month	
		Amount for Year	Amount For Previous Year	Quantity For Year	Quantity For Previous Year	Number For Year	Number For Previous Year
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Residential						
2	Residential Service	$ 518,664,740	$ 526,720,858	388,498,009	415,583,113	429,870	437,964
3	Transportation	15,294,704	9,495,196	27,767,895	18,045,180	30,140	17,779
4	Cooling & Air Conditioning	3,471	3,772	6,082	5,871		
5	Commercial						
6	Firm	97,749,116	105,602,846	75,382,285	81,951,199	26,492	27,266
7	Interruptible						
8	Transportation	46,354,745	46,254,624	144,358,734	137,958,548	8,709	7,629
9	Cooling & Air Conditioning	456,795	621,041	404,859	507,144	64	70
10	Industrial						
11	Firm						
12	Interruptible	607,478	1,442,584	1,061,190	2,212,080	1	1
13	Transportation	4,791,179	4,754,249	32,174,073	32,605,925	67	63
14	Cooling & Air Conditioning						
15	Street & Yard Light Service	4,181	4,142	3,133	3,130	2	2
16	Uncompressed Vehicular NG						
17	Cogeneration	-	4,285	-	2,545	-	1
18	Off-system Sales & Storage	201,626,409	294,461,340	397,779,910	564,114,390	38	42
19	Other Sales to Public Authorities						
20	Total Natural Gas Service Revenues	$ 885,552,818	$ 989,364,937	1,067,436,170	1,252,989,125	495,383	490,817

Please note: Sum (b) Lines 3,8, & 13 = page 301 Line 7(h). Sum (b) Lines 2,4,6,9,12,15,17 & 18 = page 301 Line 1(h) Less CIP (Current & Prior) and other Revenues .
Lines (b) & (c) 20 = Sum of Lines (f) & (g) 1 & 7 on page 301 Less CIP (Current & Prior) and Other Revenues .

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NORTHWEST NATURAL GAS CO

FORM 10-K
(Annual Report)

Filed 02/28/12 for the Period Ending 02/28/12

Address	ONE PACIFIC SQUARE 220 N.W. SECOND AVE. PORTLAND, OR 97209
Telephone	5032264211
CIK	0000073020
Symbol	NWN
SIC Code	4924 - Natural Gas Distribution
Industry	Natural Gas Utilities
Sector	Utilities
Fiscal Year	12/31

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GLOSSARY OF TERMS

Average weather: equal to the 25-year average degree days based on temperatures established in our last Oregon general rate case.

Bcf: one billion cubic feet, a volumetric measure of natural gas, roughly equal to 10 million therms or one trillion Btu's.

Btu: British thermal unit, a basic unit of thermal energy measurement. One Btu equals the energy required to raise one pound of water one degree Fahrenheit at atmospheric pressure and 60 degrees Fahrenheit. One hundred thousand Btu's equal one therm.

Core utility customers: residential, commercial and industrial customers receiving firm service from the utility.

Cost of gas sold: the delivered cost of natural gas sold to customers, including the cost of gas purchased or withdrawn/produced from storage inventory or reserves, gains and losses from gas commodity hedges, pipeline demand costs, seasonal demand cost balancing adjustments, regulatory gas cost deferrals and company gas use.

Decoupling: a rate mechanism, also referred to as our conservation tariff, which is designed to break the link between earnings and the quantity of natural gas consumed by customers. The design is intended to allow the utility to encourage customers to conserve energy while not adversely affecting its earnings due to reductions in sales volumes.

Degree days: units of measure that reflect temperature-sensitive consumption of natural gas, calculated by subtracting the average of a day's high and low temperatures from 65 degrees Fahrenheit.

Demand cost: a component in core utility customer rates that covers the cost of securing firm pipeline capacity to meet peak demand, whether that capacity is used or not.

Firm service: natural gas service offered to customers under contracts or rate schedules that will not be disrupted to meet the needs of other customers, particularly during cold weather.

General rate case: a periodic filing with state or federal regulators to establish equitable rates and balance the interests of all classes of customers and our shareholders.

Interruptible service: natural gas service offered to customers (usually large commercial or industrial users) under contracts or rate schedules that allow for interruptions when necessary to meet the needs of firm service customers.

Liquefied natural gas (LNG): the cryogenic liquid form of natural gas. To reach a liquid form at atmospheric pressure, natural gas must be cooled to approximately -260 degrees Fahrenheit.

Purchased gas adjustment (PGA): a regulatory mechanism for adjusting customer rates to reflect changes in the expected cost to acquire and deliver natural gas supplies.

Return on equity (ROE): a measure of corporate profitability, calculated as net income divided by average common stock equity. Authorized ROE refers to the equity rate approved by a regulatory agency for utility investments funded by common stock equity.

Sales service: service provided whereby a customer purchases both natural gas commodity supply and transportation from the utility.

Therm: the basic unit of natural gas measurement, equal to 100,000 Btu's.

Transportation service: service provided whereby a customer purchases natural gas commodity directly from a supplier but pays the utility to transport the gas over its distribution system to the customer's facility.

Utility margin: utility gross revenues less the associated cost of gas sold, including regulatory adjustments and applicable revenue taxes. Also referred to as utility net operating revenues.

Weather normalization: a rate mechanism applied to residential and commercial customers' bills to adjust residential and commercial customer billings based on temperature variances from average weather, with rate decreases when the weather is colder than average and rate increases when the weather is warmer than average.

General Rate Cases

Oregon. On December 30, 2011, we filed an application for a general rate increase at the OPUC. In the filing, we have requested an increase in authorized annual Oregon jurisdictional revenues of $43.7 million, equivalent to a rate increase of 6.2 percent. The amount and percent of this rate increase includes an estimated $15.1 million that represents the cumulative effect of declining use per customer. This cost is already included in customers' current rates through the operation of the Company's conservation tariff, which has been in place since 2003. The increase also includes costs related to pension contributions and additional utility services. The filing also requests an authorized overall rate of return on capital of 8.28 percent, with a return on common stock equity (ROE) of 10.3 percent and a capital structure of 50 percent common equity. In addition, we have requested the establishment of rate recovery mechanisms for deferred costs related to our environmental liabilities. The filing also requests rate redesign for residential customers with a higher fixed fee, which would effectively combine and incorporate the effects of the weather normalization and decoupling tariffs in the new fixed fee amount. The new rates are requested to be effective by November 1, 2012. We are unable to predict the outcome of this rate proceeding.

Our most recent general rate case in Oregon was effective September 2003. The OPUC authorized rates to customers based on an ROE of 10.2 percent. In 2007, in connection with the renewal of our conservation tariff and weather normalization rate mechanism, the OPUC approved a stipulation that restricted us from filing a general rate case in Oregon prior to September 2011. However, in 2011 the OPUC approved our gas reserve acquisition (see "Rate Mechanisms—Gas Reserves" below) with a condition that we file a general rate case by the end of 2011. These agreements did not impact our requirement to file annual rate adjustments to reflect changes in gas purchase costs under the PGA mechanism or our ability to collect or refund prior year's gas cost deferrals. See "Rate Mechanisms—Purchased Gas Adjustment," below.

Washington. Our most recent general rate case in Washington was in 2008, and in it the WUTC authorized rates to customers based on an ROE of 10.1 percent and an overall rate of return of 8.4 percent. These customer rates went into effect on January 1, 2009, with annual revenue requirements increased by $2.7 million or 3 percent.

FERC Jurisdiction. We are required under our Mist interstate storage certificate authority and rate approval orders to file every five years either a petition for rate approval or a cost and revenue study to change or justify maintaining the existing rates for our interstate storage services. Our most recent filing of a cost and revenue study was in April 2008. As a result of that proceeding, the current maximum cost-based rates for our interstate gas storage services were approved by FERC, with maximum rates unchanged from prior levels approved by FERC in 2005. In addition, we made a filing in December 2008 to obtain FERC approval to revise the depreciation rates associated with Mist assets used to derive the cost-based interstate storage rates. These new depreciation rates were designed to match the depreciation rates for the same type of assets approved under state regulation . We did not make any changes to the previously approved maximum rates, and FERC approved the depreciation rate filing in May 2009. We are required to make our next cost and revenue study filing at FERC on or before December 11, 2013.

California. Gill Ranch is authorized by the CPUC to charge market-based rates for the intrastate storage services offered to customers in California.

Rate Mechanisms

Purchased Gas Adjustment. Rate changes are established for the utility each year under PGA mechanisms in Oregon and Washington to reflect changes in the expected cost of natural gas commodity purchases, including contract gas purchase prices, gas prices hedged with financial derivatives or physical gas reserves, gas inventory prices, interstate pipeline demand costs, the application of temporary rate adjustments to amortize balances in deferred regulatory accounts and the removal of temporary rate adjustments effective for the previous year.

In October 2011, the OPUC and WUTC approved PGA rate changes effective November 1, 2011. The effect of these rate changes was to decrease the average monthly bills of Oregon and Washington residential customers by about 2 percent. This was our third consecutive year of PGA rate decreases, and cumulatively our average utility residential customer bills declined 20 percent in Oregon and 26 percent in Washington since 2008.

Under the current PGA mechanism in Oregon, there is an incentive sharing provision whereby we are required to select each year either an 80 percent or 90 percent deferral of higher or lower actual gas costs compared to estimated PGA prices, such that the impact on current earnings from the incentive sharing is either 20 percent or 10 percent of the difference between actual and estimated gas costs, respectively. In addition to the gas cost incentive sharing mechanism, we are subject to an annual earnings test to determine if the utility is earning above its authorized ROE threshold. If utility earnings exceed a specific ROE level, then 33 percent of the amount above that level is required to be deferred for refund to customers. Under this provision, if we select the 80 percent deferral option, then we retain all of our earnings up to 150 basis points above the currently authorized ROE. If we select the 90 percent deferral option, then we retain all of our earnings up to 100 basis points above the currently authorized ROE. We selected the 90 percent deferral option for the 2009-10, the 2010-2011 and the 2011-2012 PGA years. The ROE threshold is subject to adjustment annually based on movements in long-term interest rates. For calendar years 2009 and 2010, the ROE threshold after adjustment for long-term interest rates was 11.5 percent and 11.02 percent, respectively. No amounts were required to be refunded to customers as a result of the 2009 utility earnings test, while we are refunding $0.2 million to customers in the current PGA for the 2010 utility earnings test. For 2011, we accrued an estimated $1.5 million for potential refund to customers in the next PGA.

There has been no change to the Washington PGA mechanism under which we defer 100 percent of the higher or lower actual gas costs, with those cost differences passed on to customers through an adjustment to future rates.

Gas Reserves. In April, 2011 the OPUC approved the Encana gas reserve transaction for utility customers and determined that the Company's costs under the agreement will be recovered, plus a rate base return on our investment, on an ongoing basis through our annual PGA mechanism, including the regulatory deferral and incentive sharing process for the commodity cost of gas. Annually, a forecast will be established for the amounts related to costs and volumes expected, and any variances between forecasted and actual results will be subject to our PGA incentive sharing in Oregon, up to a maximum variance of $10 million of which 10 percent (or $1 million maximum) would be recognized in current income. Variances in excess of $10 million, both negative and positive, will be deferred and passed through to customers in future rates at 100 percent.

Conservation Tariff. In October 2002, the OPUC authorized the implementation of a "conservation tariff" to adjust utility margin for changes in consumption patterns due to residential and commercial customers' conservation efforts. The conservation tariff is a decoupling mechanism that is intended to break the link between utility earnings and the quantity of gas consumed by customers, removing any financial incentive by the utility to discourage customers' efforts to conserve energy. In Washington, customer use is not covered by a conservation or decoupling tariff, and as such our utility earnings are affected by increases and decreases in usage based on customers' conservation efforts. Washington customers account for about 10 percent of our utility volumes and revenues.

The Oregon conservation tariff includes two components: (1) an annual price elasticity adjustment, which adjusts rates for increases or decreases from expected customer volumes due to changes in commodity costs or changes in our general rates; and (2) a monthly conservation adjustment, which adjusts margin revenues to account for the difference between actual and expected customer volumes (also referred to as the decoupling adjustment). The margin adjustment resulting from differences between actual and expected volumes under the decoupling component is recorded to a deferral account, which is included in the next annual PGA filing. Baseline consumption was determined by customer consumption data used in the 2003 Oregon general rate case and is adjusted annually for customer growth and the effect of the price elasticity adjustment discussed above. From 2003 to 2011, we have experienced approximately 14 percent decline in average use per residential customer and approximately 8 percent decline in average use per commercial customer. As a result of these declines, customers have paid surcharges related to a decoupling adjustment in seven of the past nine heating seasons. See "Business Segments - Utility Operations," below.

In 2005, an independent study was commissioned to measure the effectiveness of Oregon's conservation tariff mechanism. The results of this study recommended continuation of the tariff with minor modifications. The tariff modifications were approved by the OPUC, and the mechanism was extended through October 2012.

Weather Normalization Tariff. In Oregon, we have an approved weather normalization mechanism applied to residential and commercial customer bills. This mechanism is designed to help stabilize the collection of fixed costs by adjusting residential and commercial customer billings based on temperature variances from average weather, with rate decreases when the weather is colder than average and rate increases when the weather is warmer than average. The mechanism is applied to bills between December 1 and May 15 of each heating season. The mechanism adjusts the margin component of customers' rates to reflect average weather, which uses the 25-year average temperature for each day of the billing period. Daily average temperatures and 25-year average temperatures are based on a set point temperature of 59 degrees Fahrenheit for residential customers and 58 degrees Fahrenheit for commercial customers (see "Business Segments - Utility Operations," below). The weather normalization mechanism for Oregon utility operations is approved through October 2012. Customers in Oregon are allowed to opt out of the weather normalization mechanism, and as of December 31, 2011, 9 percent had opted out. We do not have a weather normalization mechanism approved for Washington customers, which account for about 10 percent of our utility volumes and revenues.

Industrial Tariffs. The OPUC and WUTC approve tariffs covering utility service to our major industrial customers, including terms which are intended to give us certainty in the level of gas supplies we need to acquire to serve this customer group. The terms include, among other things, an annual election period, special pricing provisions for out-of-cycle changes, and a requirement that industrial customers under our annual PGA tariff complete the term of their service election.

System Integrity Program. Since 2002, various laws requiring minimum standards for integrity management programs and system integrity programs (SIP) for natural gas distribution pipelines have been enacted. Most recently, in January 2012 the "Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011" was signed into law and requires increased civil penalties for pipeline safety violations, improvements in prevention programs for pipelines, and additional review and analysis of various aspects of gas transmission lines. We are working diligently with industry associations and federal and state regulators to ensure NW Natural's compliance with the provisions of this new law.

The OPUC has approved specific accounting treatment and cost recovery for our transmission pipeline integrity management program, SIP, and the related rules adopted by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). We record the costs related to the integrity management program as either capital expenditures or regulatory assets, accumulate the costs over each 12-month period, and recover the revenue requirement associated with the costs, subject to audit, through rate changes effective with the annual PGA in Oregon. Our SIP costs are tracked into rates annually, with rate recovery after the first $3.3 million of capital costs. An annual cap for expenditures has been set at $12 million, but extraordinary costs above the cap may be approved with written consent of the OPUC staff and other interested parties and approval of the OPUC. The SIP allows recovery of costs incurred in Oregon during the period from October 2008 through the effective date of our next general rate case. We do not have any special accounting or rate treatment for our SIP costs incurred in the state of Washington.

Environmental Costs. The OPUC has authorized us to defer environmental costs associated with certain named sites and to accrue a carrying cost on environmental costs paid, subject to an annual demonstration that we have maximized our insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses. Through a series of extensions, the authorized cost deferral and accrual of carrying costs was extended through January 2012. In January 2012, we filed a request with the OPUC to continue our deferral of these environmental costs. See Note 15 for further discussion of our regulatory and insurance recovery of environmental costs.

The WUTC has also authorized the deferral of environmental costs, if any, that are incurred in connection with services provided to Washington customers. The order granting approval of that request was effective January 26, 2011.

Pension Deferral. Effective January 1, 2011, the OPUC approved our request to defer annual pension expenses above the amount set in rates in our last general rate case, with recovery of these deferred amounts through the implementation of a balancing account, which includes the expectation of higher and lower pension expenses in future years. Our recovery of these deferred balances includes accrued interest on the account balance at the utility's authorized rate of return, which is currently 8.62 percent. The reduction to operations and maintenance expense for 2011 was $6.0 million. Future years' deferrals will depend on changes in plan assets and projected benefit liabilities using a number of key assumptions, as well as our pension contributions. We estimate deferrals totaling $8 million to $9 million in 2012. See "Application of Critical Accounting Policies and Estimates," above.

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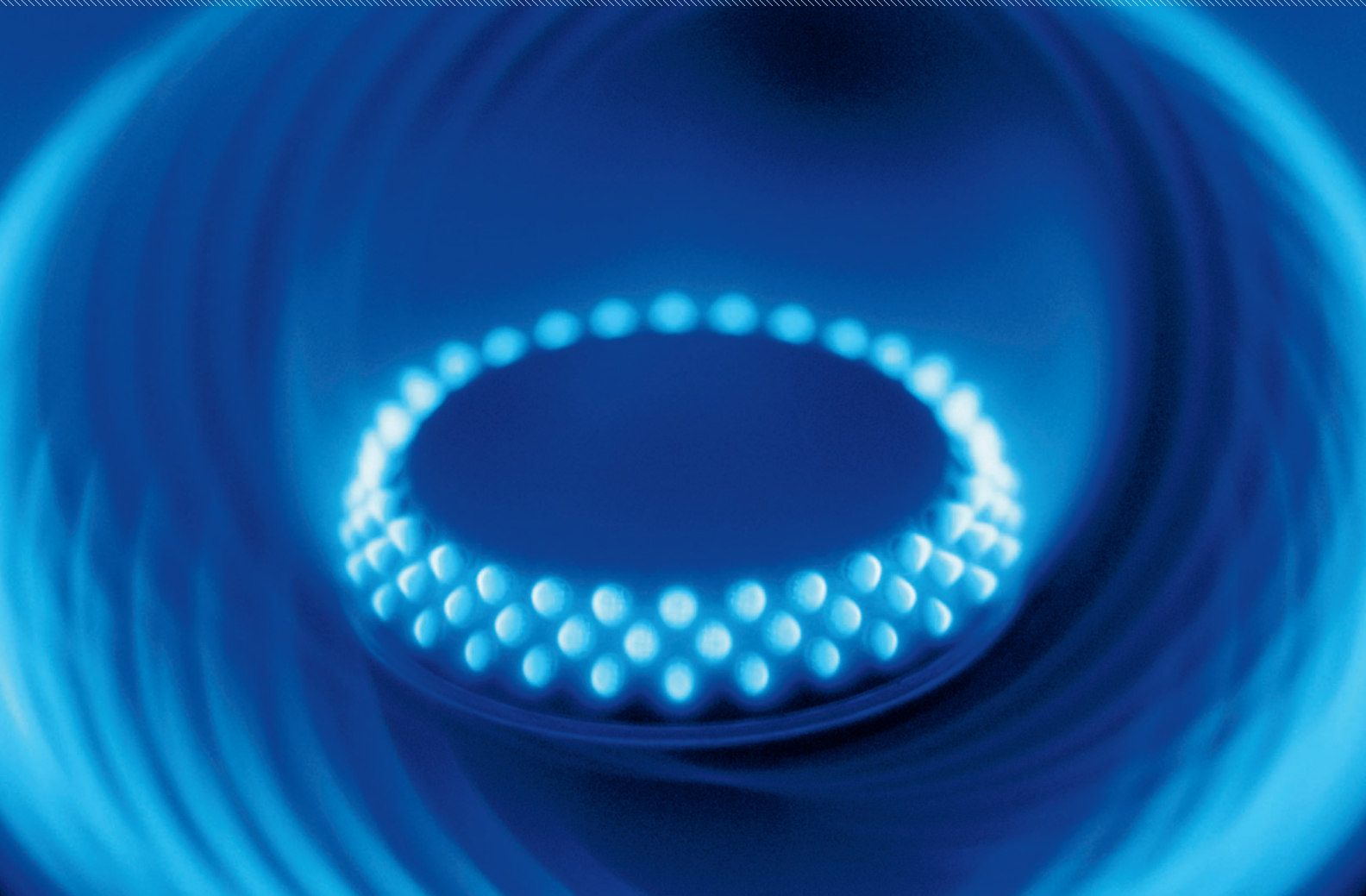
NW NATURAL 2011 ANNUAL REPORT



COMPARATIVE OPERATING STATISTICS

Selected Utility Data	2011	2010	2009	2008	2007
Gas sales and transportation deliveries (000 therms):					
Residential	425,139	368,682	412,867	428,787	398,960
Commercial	259,675	230,196	255,593	265,531	249,659
Industrial firm	37,344	37,085	39,447	47,340	52,340
Industrial interruptible	59,308	58,387	72,525	87,484	89,128
Total gas sales	781,466	694,350	780,432	829,142	790,087
Transportation	370,888	367,619	350,933	431,609	424,882
Total volumes delivered	1,152,354	1,061,969	1,131,365	1,260,751	1,214,969
Operating revenues and cost of sales ($000):					
Utility operating revenues:					
Residential	492,490	456,174	555,844	566,840	555,312
Commercial	244,922	227,994	292,697	298,943	298,800
Industrial firm	30,455	30,830	41,407	46,579	54,567
Industrial interruptible	34,961	36,164	62,116	68,978	74,876
Total gas sales revenues	802,828	751,162	952,064	981,340	983,555
Transportation	15,419	13,833	13,635	14,288	14,191
Regulatory adjustment for income taxes paid	(7,162)	7,721	5,884	1,760	5,996
Other	11,134	17,917	21,166	21,784	12,228
Total utility operating revenues	822,219	790,633	992,749	1,019,172	1,015,970
Cost of gas sold	458,508	424,494	611,088	656,504	639,094
Revenue taxes	20,741	19,991	24,656	25,072	25,001
Utility net operating revenues	342,970	346,148	357,005	337,596	351,875
Customer and weather data:					
Total customers	679,543	673,997	667,794	662,341	652,012
Actual degree days	4,652	4,171	4,383	4,576	4,374
Percent colder (warmer) than average	9%	(2)%	3%	7%	3%
Average use per customer (therms):					
Residential	690	616	686	721	687
Commercial	4,073	3,699	4,113	4,300	4,110
Gas purchases (000 therms)	805,196	716,509	784,982	829,989	806,905
Gas purchased cost per therm - net (cents)	56.60	63.07	71.96	86.56	75.00
Average sendout cost of gas (cents)	58.93	61.36	78.40	79.21	80.89
Maximum day firm sendout (000 therms)	5,178	5,764	6,980	6,609	5,845
Maximum day total sendout (000 therms)	6,724	7,252	8,339	8,363	7,344
Total employees at year-end	1,050	1,028	1,061	1,133	1,141
Number of customers served by each operating employee	975	1,077	979	932	924

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PIEDMONT NATURAL GAS CO INC

FORM 10-K
(Annual Report)

Filed 12/23/11 for the Period Ending 10/31/11

Address	4720 PIEDMONT ROW DR CHARLOTTE, NC 28210
Telephone	7043643120
CIK	0000078460
Symbol	PNY
SIC Code	4924 - Natural Gas Distribution
Industry	Natural Gas Utilities
Sector	Utilities
Fiscal Year	10/31

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Our utility operations are regulated by the North Carolina Utilities Commission (NCUC), the Public Service Commission of South Carolina and the Tennessee Regulatory Authority (TRA) as to rates, service area, adequacy of service, safety standards, extensions and abandonment of facilities, accounting and depreciation. The NCUC also regulates us as to the issuance of long-term debt and equity securities. We are also subject to or affected by various federal regulations. These federal regulations include regulations that are particular to the natural gas industry, such as regulations of the Federal Energy Regulatory Commission (FERC) that affect the purchase and sale of and the prices paid for the interstate transportation and storage of natural gas, regulations of the U.S. Department of Transportation (DOT) that affect the design, construction, operation, maintenance, integrity, safety and security of natural gas distribution and transmission systems, and regulations of the Environmental Protection Agency relating to the environment. In addition, we are subject to numerous other regulations, such as those relating to employment and benefit practices, which are generally applicable to companies doing business in the United States of America.

Our regulatory commissions approve rates and tariffs that are designed to give us the opportunity to generate revenues to cover our gas and non-gas costs and to earn a fair rate of return on invested capital for our shareholders. Our ability to earn our authorized rates of return is based in part on our ability to reduce or eliminate regulatory lag and also by improved rate designs that decouple the recovery of our approved margins from customer usage patterns impacted by seasonal weather patterns and customer conservation.

In North Carolina, a margin decoupling mechanism provides for the recovery of our approved margin from residential and commercial customers on a year around basis independent of consumption patterns. The margin decoupling mechanism results in semi-annual rate adjustments to refund any over-collection of margin or recover any under-collection of margin. We have weather normalization adjustment (WNA) mechanisms in South Carolina and Tennessee that partially offset the impact of colder- or warmer-than-normal winter weather on bills rendered during the months of November through March for residential and commercial customers. The WNA formula calculates the actual weather variance from normal, using 30 years of history, which increases revenues when weather is warmer than normal and decreases revenues when weather is colder than normal. The gas cost portion of our costs is recoverable through purchased gas adjustment (PGA) procedures and is not affected by the margin decoupling mechanism or the WNA. For further information, see Note 2 to the consolidated financial statements.

We continually assess alternative rate structures and cost recovery mechanisms that are more appropriate to the changing energy economy. We have been pursuing alternatives to the traditional utility rate design that provide for the collection of margin revenue based on volumetric throughput with new rate designs and incentives that allow utilities to encourage energy efficiency and conservation. By decoupling the link between energy consumption and margin revenues, our interests are aligned with our customers' interests on conservation and energy efficiency. In North Carolina, we have decoupled residential and commercial rates. In South Carolina, we operate under a rate stabilization mechanism that achieves the objectives of margin decoupling for residential and commercial customers with a one year lag. For the twelve months ended October 31, 2011, these and other rate designs stabilized our gas utility margin by providing fixed recovery of 70% of our utility margins, including margin decoupling in North Carolina, facilities charges to our customers and fixed-rate contracts; semi-fixed recovery of 18% of our utility margins, including the rate stabilization mechanism in South Carolina and WNA in South Carolina and

ANNUAL REPORT OF MAJOR NATURAL GAS COMPANIES

01 Exact Legal Name of Respondent Piedmont Natural Gas Company	02 Year of Report December 31, 2011
03 Previous Name and Date of Change (if name changed during year)	
04 Address of Principal Business Office at End of Year (Street, City, State, Zip Code) 4720 Piedmont Row Drive, Charlotte, NC 28210	
05 Name of Contact Person Jose M. Simon	06 Title of Contact Person Vice President and Controller
07 Address of Contact Person (Street, City, State, Zip Code) PO Box 33068, 4720 Piedmont Row Drive, Charlotte, NC 28233	

08 Telephone of Contact Person, Including Area Code (704) 731- 4327	09 This Report is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report (Mo, Da, Yr) April 1, 2012

The undersigned officer certifies that he/she has examined the accompanying report; that to the best of his/her knowledge, information, and belief, all statements of fact contained in the accompanying report are true and the accompanying report is a correct statement of the business and affairs of the named respondent in respect to each and every matter set forth therein during the period from and including January 1 to and including December 31 of the year of the report.

01 Name Jose M. Simon	02 Title Vice President and Controller
03 Signature /s/ Jose M. Simon	04 Date Signed (Mo, Day, Yr) March 22, 2012

Title 18, U.S.C. 1001, makes it a crime for any person knowingly and willfully to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Gas Companies
STATISTICAL DATA - FOR THE YEAR ENDED DECEMBER 31, 2011
COMPANY NAME: Piedmont Natural Gas Company

Data for North Carolina Operations Only	$ Amount or Number	
1 Total of miles of mains - ~~3 inch equivalent~~ linear miles	17,609.9	
2 Degree Days System average (may be specific area if designated)	3,154	
3 Estimated population of area served	6,108,000	
4 Estimated square miles in area served	32,737	
5 Number of tobacco curing customers (indicated if included in any other classification)	None	
6 Number of Public Housing meters (indicated in other residential customer count)	Not Available	
7 Number of Public Housing units (indicated in other residential customer count)	Not Available	
8 Annual average number of Residential Space Heating customers (This should agree with the data furnished in annual report on Page 568)	605,444	
9 Estimated average MCF per customer for the year for space heating only	55.7	
10 Annual average revenue per Residential Space Heating Customer	Not Available	
11 Annual average revenue per MCF per Residential Space Heating Customer	Not Available	
12 Annual number of interruptible and Off Peak customers for the year	-	(1)
13 DT of gas sales for the year - Interruptible and Off Peak	-	(1)
14 Total revenues from sale of Interruptible and Off Peak Gas	-	(1)
15 Average number of Firm customers for the year	671,434 *	
16 Dts of gas sales for the year - Firm	218,720,785 *	
17 Total revenues from the sales of Firm Gas (excluding Secondary Market sales)	$780,515,490 *	

North Carolina Employee Data

18 Number of full-time North Carolina Employees:	Yearly Average	1,439
	Year End	1,434
(For Multi-State operations - NC count may be based on addresses shown on W-2 statements)		
19 Total wages and salaries paid North Carolina Employees (excluding severance)		$97,208,840
20 Average annual salaries and wages per Employee (excluding severance)		$67,553

(1) A breakdown between firm and interruptible revenues, dekatherms, and customers is not readily available.

*Included in these lines are interruptible customers, dekatherms, and revenues.

ANNUAL REPORT OF MAJOR NATURAL GAS COMPANIES

01 Exact Legal Name of Respondent	02 Year of Report
Piedmont Natural Gas Company	December 31, 2011

03 Previous Name and Date of Change (if name changed during year)

04 Address of Principal Business Office at End of Year (Street, City, State, Zip Code)

4720 Piedmont Row Drive, Charlotte, NC 28210

05 Name of Contact Person	06 Title of Contact Person
Jose M. Simon	Vice President and Controller

07 Address of Contact Person (Street, City, State, Zip Code)

PO Box 33068, 4720 Piedmont Row Drive, Charlotte, NC 28233

08 Telephone of Contact Person, Including Area Code	09 This Report is	10 Date of Report (Mo, Da, Yr)
(704) 731- 4327	(1) [X] An Original (2) [ ] A Resubmission	April 1, 2012

The undersigned officer certifies that he/she has examined the accompanying report; that to the best of his/her knowledge, information, and belief, all statements of fact contained in the accompanying report are true and the accompanying report is a correct statement of the business and affairs of the named respondent in respect to each and every matter set forth therein during the period from and including January 1 to and including December 31 of the year of the report.

01 Name	02 Title
Jose M. Simon	Vice President and Controller
03 Signature	04 Date Signed (Mo, Day, Yr)
/s/ Jose M. Simon	March 22, 2012

Title 18, U.S.C. 1001, makes it a crime for any person knowingly and willfully to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent Piedmont Natural Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/01/12	Year of Report Dec. 31, 2011
		GAS OPERATING REVENUES	South Carolina
	Revenue	DT of Gas Sold	Average # of Customers Per Month
Title Of Account	Amount For Year	Amount For Year	Amount For Year
(480) Residential Sales	76,868,740	6,500,211	116,794
(481) Commercial & Industrial Sales			
Small (or Commercial)	41,264,784	4,185,914	13,479
Large (or Industrial)	12,480,781	1,639,360	371
(484.2) Power Generation Sales	1,285,845	245,743	1
(482) Other Sales to Public Authorities	556,392	52,324	1,524
(484) Interdepartmental Sales			
Total Sales to Customers	132,456,542	12,623,552	132,169

ANNUAL REPORT OF MAJOR NATURAL GAS COMPANIES

01 Exact Legal Name of Respondent	02 Year of Report
Piedmont Natural Gas Company	December 31, 2011

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Jose M. Simon	Vice President and Controller

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(704) 731- 4327	(1) [X] An Original (2) [ ] A Resubmission	April 1, 2012

The undersigned officer certifies that he/she has examined the accompanying report; that to the best of his/her knowledge, information, and belief, all statements of fact contained in the accompanying report are true and the accompanying report is a correct statement of the business and affairs of the named respondent in respect to each and every matter set forth therein during the period from and including January 1 to and including December 31 of the year of the report.

01 Name	02 Title
Jose M. Simon	Vice President and Controller
03 Signature	04 Date Signed (Mo, Day, Yr)
/s/ Jose M. Simon	March 22, 2012

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Name of Respondent	This Report is:	Date of Report	Year of Report
Piedmont Natural Gas Company	(1) X_ An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/01/12	Dec. 31, 2011

GAS OPERATING REVENUES AND EXPENSES

	Particulars (a)	Tennessee Intra-state Operations (b) This Year	Tennessee Intra-state Operations (c) Last Year	Difference (d)	
8	OPERATING REVENUES				8
9	SALES OF GAS				9
10	Residential Sales (480)	109,640,601	119,281,104	(9,640,503)	10
11	Commercial and Industrial Sales (481)	65,073,437	73,011,986	(7,938,549)	11
12	Other Sales to Public Authorities (482)				12
13	Sales for Resale (483)	187,029	443,662	(256,633)	13
14	Interdepartmental Sales (484)				14
15	Other (Please Specify)				15
16	Other (Please Specify)				16
17	**Total Sales of Gas**	174,901,067	192,736,752	(17,835,685)	17
18					18
19	OTHER OPERATING REVENUES				19
20	Forfeited Discounts (487)	1,832,412	1,597,478	234,934	20
21	Miscellaneous Service Revenues (488)	310,277	262,928	47,349	21
22	Revenues from Transporation of Gas of Others (489)	10,965,960	10,199,644	766,316	22
23	Rent from Gas Property (493)	2,117	(700)	2,817	23
24	Interdepartmental Rents (494)				24
25	Other Gas Revenues (495)	2,731,397	1,835,351	896,046	25
26	Other (Please Specify)				26
27	**Total Other Operating Revenues**	15,842,163	13,894,701	1,947,462	27
28	**Total Operating Revenues (400)**	190,743,230	206,631,453	(15,888,223)	28
29					29
30	OPERATING EXPENSES				30
31	Gas Production Expenses (700-798)	1	625	(624)	31
32	Purchased Gas Expenses (800-813)	97,475,120	111,675,653	(14,200,533)	32
33	**Total Production Expenses**	97,475,121	111,676,278	(14,201,157)	33
34	Underground Storage Expenses (814-837)				34
35	Other Storage Expenses (840-848.3)	857,884	861,472	(3,588)	35
36	Transmission Expenses (850-867)	597,042	604,159	(7,117)	36
37	Distribution Expenses (870-894)	12,954,566	11,117,646	1,836,920	37
38	Customer Accounts Expenses (901-905)	3,239,900	2,603,486	636,414	38
39	Customer Service Expenses (909-912)	209,560	232,915	(23,355)	39
40	Sales Expenses (915-918)	811,043	1,018,791	(207,748)	40
41	Administrative and General Expenses (920-932)	22,683,519	14,846,913	7,836,606	41
42	Other (Please Specify)				42
43	Other (Please Specify)				43
44	**Total Operation and Maintenance**	138,828,635	142,961,660	(4,133,025)	44
45	Depreciation Expense (403)	22,910,671	21,722,115	1,188,556	45
46	Amortization and Depletion of Producing Natural Gas Land (404.1)				46
47	Amortization of Underground Storage Land (404.2)				47
48	Amortization of Other Limited-Term Utility Plant (404.3)	43,322	42,477	845	48
49	Amortization of Other Utility Plant (405)				49
50	Amortization of Utility Plant Acquisition Adjustments (406)				50
51	Amortization of Property Losses (407.1)				51
52	Amortization of Conversion Expenses (407.2)				52
53	Taxes Other than Income Taxes (408.1)	11,730,548	8,417,368	3,313,180	53
54	Income Taxes (409.1)	2,856,107	9,500,432	(6,644,325)	54
55	Provision for Deferred Income Taxes, Operating (410.1)	(32,067)	(32,067)	0	55
56	Income Taxes Deferred in Prior Years-Credit, Operating (411.1)				56
57	Investment Tax Credits, Deferred (412.1)				57
58	Investment Tax Credits, Restored (412.2)	99,739	34,982	64,757	58
59	Other (Please Specify)				59
60	Other (Please Specify)				60
61	**Total Operating Expenses**	176,436,955	182,646,967	(6,210,012)	61
62	**Operating Income**	14,306,275	23,984,486	(9,678,211)	62

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SOUTH JERSEY INDUSTRIES INC

FORM 10-K
(Annual Report)

Filed 02/28/12 for the Period Ending 12/31/11

Address	#1 SOUTH JERSEY PLAZA ROUTE 54 FOLSOM, NJ 08037
Telephone	6095619000
CIK	0000091928
Symbol	SJI
SIC Code	4924 - Natural Gas Distribution
Industry	Natural Gas Utilities
Sector	Utilities
Fiscal Year	12/31

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Primary Factors Affecting SJI's Business

SJI's stated long-term goals are to: 1) Grow Economic Earnings per share by an average of at least 6% to 7% per year; 2) Increase the dividend on common stock by at least 6% to 7% annually; and 3) Maintain a low-to-moderate risk platform. Management established those goals in conjunction with SJI's Board of Directors based upon a number of different internal and external factors that characterize and influence SJI's current and expected future activities.

The following is a summary of the primary factors we expect to have the greatest impact on SJI's performance and ability to achieve long-term goals going forward:

Business Model - In developing SJI's current business model, our focus has been on our core utility and natural extensions of that business. That focus enables us to concentrate on business activities that match our core competencies. Going forward we expect to pursue business opportunities that fit this model.

Customer Growth - Southern New Jersey, our primary area of operations, has not been immune to the issues impacting the new housing market nationally. However, net customers for SJG still grew 1.0% for 2011 as we increased our focus on customer conversions. In 2011, the 3,928 consumers converting their homes and businesses from other heating fuels, such as electric, propane or oil represented over 65.0% of the total new customer acquisitions for the year. In comparison, conversions over the past five years averaged 3,071 annually. Customers in our service territory typically base their decisions to convert on comparisons of fuel costs, environmental considerations and efficiencies. As such, SJG began a comprehensive partnership with the State's Office of Clean Energy to educate consumers on energy efficiency and to promote the rebates and incentives available to natural gas users.

Regulatory Environment - SJG is primarily regulated by the New Jersey Board of Public Utilities (BPU). The BPU sets the rates that SJG charges its rate-regulated customers for services provided and establishes the terms of service under which SJG operates. We expect the BPU to continue to set rates and establish terms of service that will enable SJG to obtain a fair and reasonable return on capital invested. The BPU approved a Conservation Incentive Program (CIP) effective October 1, 2006, discussed in greater detail under Results of Operations, that protects SJG's net income from reductions in gas used by residential, commercial and small industrial customers. In addition, in March 2011, the BPU approved an extension of the Capital Investment Recovery Tracker (CIRT II) allowing SJG to accelerate $60.3 million of capital spending into 2011 and 2012. Under CIRT II, the Company capitalizes a return on CIRT II investments until they are recovered in rate base as utility plant in service.

Weather Conditions and Customer Usage Patterns - Usage patterns can be affected by a number of factors, such as wind, precipitation, temperature extremes and customer conservation. SJG's earnings are largely protected from fluctuations in temperatures by the CIP. The CIP has a stabilizing effect on utility earnings as SJG adjusts revenues when actual usage per customer experienced during an annual period varies from an established baseline usage per customer. Our nonutility gas retail marketing business is directly affected by weather conditions, as it does not have regulatory mechanisms that address weather volatility. The impact of different weather conditions on the earnings of our nonutility businesses is dependent on a range of different factors. Consequently, weather may impact the earnings of SJI's various subsidiaries in different, or even opposite, ways. Further, the profitability of individual subsidiaries may vary from year-to-year despite experiencing substantially similar weather conditions.

Changes in Natural Gas and Electricity Prices - The utility's gas costs are passed on directly to customers without any profit margin added by SJG. The price the utility charges its periodic customers is set annually, with a regulatory mechanism in place to make limited adjustments to that price during the course of a year. In the event that gas cost increases would justify customer price increases greater than those permitted under the regulatory mechanism, SJG can petition the BPU for an incremental rate increase. High prices can make it more difficult for our customers to pay their bills and may result in elevated levels of bad-debt expense. Among our nonutility activities, the one most likely to be impacted by changes in natural gas prices is our wholesale gas marketing business. Wholesale gas marketing typically benefits from volatility in gas prices during different points in time. The actual price of the commodity does not typically have an impact on the performance of this business line. Our ability to add and retain customers at our retail gas marketing business is affected by the relationship between the price that the utility charges customers for gas and the cost of gas available in the market at specific points in time. However, retail gas marketing accounts for a very small portion of SJI's overall activities.

State of New Jersey
Board of Public Utilities
Two Gateway Center
Newark, New Jersey 07102

IDENTIFICATION

01 Exact Legal Name of Respondent: South Jersey Gas Company	02 Year of Report: December 31, 2011

03 Previous Name and Date of Change (if name changed during year):

04 Address of Principal Office at End of Year (Street, City, State, Zip Code):
1 South Jersey Plaza
Folsom, NJ 08037

05 Web Address of the Company:

06 Name of Contact Person: Thomas S. Kavanaugh	07 Title of Contact Person: Controller

08 Address of Contact Person (Street, City, State, Zip Code):
1 South Jersey Plaza
Folsom, NJ 08037

09 Telephone of Contact Person, Including Area Code: (609) 561-9000	10 Fax Number of Contact Person: (609) 561-8225

11 E-Mail Address of Contact Person: tkavanaugh@sjindustries.com

12 This Original Report is due on March 31, 2011: It is Filed on April 24, 2012

13 This is Resubmission Report. Date Filed on (Mo. Da. Yr.)

Name of Respondent	This Report is	Date of Report	Year of Report
South Jersey Gas Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo., Da., Yr.)	Dec. 31, 2011

GAS OPERATING REVENUES (Account 400) (Continued)

1. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
2. If increases or decreases from previous year (columns (c), (e) and (g) are not derived from previously reported figures, explain any inconsistencies in a footnote.
3. Commercial and Industrial Sales, Account 481, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 200,000 Mcf per year or approximately 800 Mcf per day of normal requirements. (See Account 481 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
4. Provide a reconciliation of the total amounts on line 20 and the amounts on the lines 1,5,6,7 and 8 of page 301 in the area provided for notes.

Line No.	Tax Class	Operating Revenues		Therms of Gas Sold		Avg. No. of Nat. Gas Customers Per Month	
	(a)	Amount For Year (b)	Amount For Previous Year (c)	Quantity For Year (d)	Quantity For Previous Year (e)	Number For Year (f)	Number for Previous Year (g)
1	Residential						
2	Residential Service	$232,454,194	$ 302,818,744	203,311,596	229,612,052	291,554	295,489
3	Transportation	15,161,132	11,907,467	23,822,922	21,362,812	33,938	26,398
4	Cooling & Air Conditioning	1,863	4,206	1,359	3,728	3	5
5	Commercial						
6	Firm	58,047,793	67,890,709	54,144,126	58,726,330	19,109	19,066
7	Interruptible	974	11,393	-	-	-	-
8	Transportation	22,940,388	22,810,150	60,506,434	67,133,586	3,792	3,653
9	Cooling & Air Conditioning	4,803	6,916	3,744	6,586	-	-
10	Industrial						
11	Firm	3,990,728	3,573,234	3,192,263	2,923,233	345	355
12	Interruptible	228,682	759,114	128,588	517,034	2	3
13	Transportation	20,113,810	17,633,468	144,568,478	137,963,206	89	93
14	Cooling & Air Conditioning	-		-	-		
15	Street & Yard Light Service	70,988	70,398	113,232	113,048	10	11
16	Capacity Rel. & Storage Serv.	7,533,944	4,156,251	634,131,590	462,783,610		
17	Cogeneration & Electric	13,210,311	12,372,175	77,281,825	66,666,167	9	7
18	Off-System Sales	37,413,129	30,756,535	80,090,310	60,337,170	14	10
19	Other Sales	1,276,455	1,211,029		-	3	4
20	Total Natural Gas Service Revenues	$412,449,194	$475,981,789	1,281,296,467	1,108,148,562	348,868	345,094

NOTES

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SOUTHWEST GAS CORP

FORM 10-K
(Annual Report)

Filed 02/28/12 for the Period Ending 12/31/11

Address	5241 SPRING MOUNTAIN RD PO BOX 98510 LAS VEGAS, NV 89193-8510
Telephone	7028767237
CIK	0000092416
Symbol	SWX
SIC Code	4923 - Natural Gas Transmission and Distribution
Industry	Natural Gas Utilities
Sector	Utilities
Fiscal Year	12/31

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The table below lists the percentage of operating margin (operating revenues less net cost of gas) by major customer class for the years indicated:

For the Year Ended	Distribution		Transportation
	Residential and Small Commercial	Other Sales Customers	
December 31, 2011	86%	4%	10%
December 31, 2010	86%	4%	10%
December 31, 2009	86%	4%	10%

Southwest is not dependent on any one or a few customers such that the loss of any one or several would have a significant adverse impact on earnings or cash flows.

Transportation of customer-secured gas to end-users accounted for 44% of total system throughput in 2011. Customers who utilized this service transported 94 million dekatherms in 2011, 100 million dekatherms in 2010, and 104 million dekatherms in 2009. Although these volumes are significant, these customers provided a much smaller proportionate share of operating margin.

The demand for natural gas is seasonal, with a greater demand in the colder winter months and decreased demand in the warmer summer months. It is the opinion of management that comparisons of earnings for interim periods do not reliably reflect overall trends and changes in operations. The decoupled rate mechanisms in place in the three-state service territory are structured with seasonal variations. Also, earnings for interim periods can be significantly affected by the timing of general rate relief.

Rates and Regulation

Rates that Southwest is authorized to charge its distribution system customers are determined by the ACC, PUCN, and CPUC in general rate cases and are derived using rate base, cost of service, and cost of capital experienced in a historical test year, as adjusted in Arizona and Nevada, and projected for a future test year in California. The FERC regulates the northern Nevada transmission and liquefied natural gas (“LNG”) storage facilities of Paiute Pipeline Company (“Paiute”), a wholly owned subsidiary, and the rates it charges for transportation of gas directly to certain end-users and to various local distribution companies (“LDCs”). The LDCs transporting on the Paiute system are: NV Energy (serving Reno and Sparks, Nevada) and Southwest (serving Truckee, South Lake Tahoe and North Lake Tahoe, California and various locations throughout northern Nevada).

Rates charged to customers vary according to customer class and rate jurisdiction and are set at levels that are intended to allow for the recovery of all prudently incurred costs, including a return on rate base sufficient to pay interest on debt as well as a reasonable return on common equity. Rate base consists generally of the original cost of utility plant in service, plus certain other assets such as working capital and inventories, less accumulated depreciation on utility plant in service, net deferred income tax liabilities, and certain other deductions.

In California, CPUC regulations allow Southwest to separate or “decouple” the recovery of operating margin from natural gas consumption. In Nevada, a decoupled rate structure applies to most customer classes, providing stability in annual operating margin. In Arizona, Southwest filed a general rate case in November 2010 and requested a rate structure to decouple recovery of the Company’s fixed costs from fluctuations in usage, and enable the Company to aggressively advocate for increased energy efficiency by its customers, which was approved in December 2011 effective January 2012.

Rate schedules in all service areas contain deferred energy or purchased gas adjustment provisions, which allow Southwest to file for rate adjustments as the cost of purchased gas changes. Deferred energy and purchased gas adjustment (collectively “PGA”) rate changes affect cash flows, but have no direct impact on profit margin. Filings to change rates in accordance with PGA clauses are subject to audit by the appropriate state regulatory commission staff.

Information with respect to recent general rate cases and PGA filings is included in the Rates and Regulatory Proceedings section of Management’s Discussion and Analysis (“MD&A”) in the 2011 Annual Report to Shareholders.

Weather Risk

Rate design is the primary mechanism available to Southwest to mitigate weather risk. As of January 2012, all of Southwest's service territories have decoupled rate structures which mitigate weather risk. In California, CPUC regulations allow Southwest to decouple operating margin from usage and offset weather risk. In Nevada, a decoupled rate structure applies to most customer classes providing stability in annual operating margin by insulating the Company from the effects of lower usage (including volumes associated with unusual weather). In Arizona, the ACC recently approved a fully decoupled rate structure with a monthly weather normalization provision effective January 2012.

Interest Rate Risk

Interest rate risk is the risk that changes in interest rates could adversely affect earnings or cash flows. The primary interest rate risk for the Company is the risk of increasing interest rates on variable-rate obligations. Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. In Nevada, fluctuations in interest rates on $100 million of variable-rate Industrial Development Revenue Bonds ("IDRBs") are tracked and recovered from ratepayers through an interest balancing account, which mitigates risk to earnings and cash flows from interest rate fluctuations on these IDRBs between general rate cases. As of December 31, 2011 and 2010, Southwest had $209 million and $100 million, respectively, in variable-rate debt outstanding, excluding the IDRBs noted above. Assuming a constant outstanding balance in variable-rate debt for the next twelve months, a hypothetical 1% change in interest rates would increase or decrease interest expense for the next twelve months by approximately $2 million.

The Company is also exposed to interest rate risk associated with new debt financing needed to fund maturities of long-term debt. Southwest has $200 million of long-term debt maturing in May 2012 and plans to fund that obligation by issuing at least $200 million of debentures by the maturity date. In connection with the planned debt issuance, the Company, in January 2010, entered into a forward-starting interest rate swap ("FSIRS") agreement to hedge the risk of interest rate variability during the period leading up to the planned issuance. The counterparties to the agreement comprise four major banking institutions. The FSIRS has a notional amount of $100 million (with Southwest as the fixed-rate payer at a rate of 4.78%) and has a mandatory termination date on or before March 20, 2012. Southwest designated the FSIRS agreement as a cash flow hedge of forecasted future interest payments.

Other risk information is included in **Item 1A. Risk Factors** of this report.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The Consolidated Financial Statements of Southwest Gas Corporation and Notes thereto, together with the report of PricewaterhouseCoopers LLP, are included in the 2011 Annual Report to Shareholders and are incorporated herein by reference.

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

Item 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

The Company has established disclosure controls and procedures that are designed to provide reasonable assurance that information required to be disclosed in reports filed or submitted under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms and to provide reasonable assurance that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and benefits of controls must be considered relative to their costs. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or management override of the control. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and may not be detected.

ARIZONA CORPORATION COMMISSION
UTILITIES DIVISION

ANNUAL REPORT MAILING LABEL - MAKE CHANGES AS NECESSARY

G-01551A
SOUTHWEST GAS CORPORATION
5241 SPRING MOUNTAIN ROAD
PO BOX 98510
LAS VEGAS NV 89193-8510

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MAR 30 2012

AZ CORP COMM
Director - Utilities

ANNUAL REPORT

FOR YEAR ENDING

12	31	2011

FOR COMMISSION USE

ANN 02	11

4-2-12

SERVICES AUTHORIZED TO PROVIDE

Check the following box/s for the services that you are authorized to provide:

- [x] **Gas**
  - [x] Natural Gas
  - [ ] Propane
- [ ] **Other** (Specify) _____

STATISTICAL INFORMATION (ARIZONA ONLY)

GAS UTILITIES ONLY

Total number of customers	**1,001,476**
Residential	**960,670**
Commercial	**39,878**
Industrial	**222**
Irrigation	**328**
Other	**10**
Transportation	**368**
Total therms sold	**560,590,780** therms
Residential	**296,022,800**
Commercial	**210,610,210**
Industrial	**19,510,440**
Irrigation	**10,980,790**
Other	**23,466,540**

Filing Accepted
Effective
MAY 15 2012
Public Utilities Commission
of Nevada

NEVADA

ACCEPTED
05/15/12 JY

STATE STATISTICS

2011

FERC FORM NO. 2:
ANNUAL REPORT OF MAJOR NATURAL GAS COMPANIES

IDENTIFICATION

01 Exact Legal Name of Respondent SOUTHWEST GAS CORPORATION	02 Year of Report 2011
03 Previous Name and Date of Change *(If name changed during year)* NOT APPLICABLE	
04 Address of Principal Office at End of Year *(Street, City, State, Zip Code)* 5241 SPRING MOUNTAIN ROAD, LAS VEGAS, NEVADA 89150	
05 Name of Contact Person GREGORY J. PETERSON	06 Title of Contact Person VICE PRESIDENT / CONTROLLER / CAO
07 Address of Contact Person *(Street, City, State, Zip Code)* 5241 SPRING MOUNTAIN ROAD, LAS VEGAS, NEVADA 89150	

08 Telephone of Contact Person, Including Area Code (702) 876-7120	09 This report is: [X] An Original [ ] A Resubmission	10 Date of Report (Mo, Da, Yr) December 31, 2011

ATTESTATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

11 Name GREGORY J. PETERSON	12 Title VICE PRESIDENT / CONTROLLER / CAO
13 Signature	14 Date Signed MAY 14, 2012

Title 18, U.S.C. 1001, makes it a crime for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

SOUTHWEST GAS CORPORATION
NEVADA
December 31, 2011

	Title of Account	OPERATING REVENUES		DEKATHERMS OF NATURAL GAS SOLD		AVG NUMBER OF NATURAL GAS CUSTOMERS PER MONTH	
		Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
	GAS SERVICE REVENUES						
480	Residential Sales	328,321,712	372,182,939	32,101,150	31,626,791	634,096	626,567
481	Commercial Sales	120,783,819	145,426,927	16,493,950	16,385,038	28,099	28,030
	Industrial Sales	3,490,227	4,342,845	417,766	425,024	54	54
482	Other Sales to Public Authorities	49,157		9,234		-	
484	Interdepartmental Sales						
	TOTAL Sales to Ultimate Customers	452,644,915	521,952,711	49,022,100	48,436,853	662,249	654,651
483	Sales for Resale						
	TOTAL Gas Service Revenues	452,644,915	521,952,711	49,022,100	48,436,853	662,249	654,651
	OTHER OPERATING REVENUES						
485	Intracompany Transfers						
487	Forfeited Discounts	3,577,605	4,082,380				
488	Miscellaneous Service Revenues	6,119,304	6,115,696				
489.1	Revenues from Transportation of Gas of Others Through Gathering Facilities						
489.2	Revenues from Transportation of Gas of Others Through Transmission Facilities						
489.3	Revenues from Transportation of Gas of Others Through Distribution Facilities	22,909,310	24,014,707	62,874,477	67,554,934		
489.4	Revenues from Storing Gas of Others						
490	Sales of Prod. Ext. from Nat. Gas						
491	Rev. from Nat. Gas Proc. By Others						
492	Incidental Gasoline and Oil Sales						
493	Rent from Gas Property	1,167,612	1,106,136				
494	Interdepartmental Rents						
495	Other Gas Revenues	(3,337,482)	(2,989,886)				
	TOTAL Other Operating Revenues	30,436,349	32,329,033				
	TOTAL Gas Operating Revenues	483,081,264	554,281,744				
496	(less) Provision for Rate Refunds						
	TOTAL	483,081,264	554,281,744				

[Next page is 317]

CALIFORNIA

STATE STATISTICAL REPORT

2011

ANNUAL REPORT OF MAJOR NATURAL GAS COMPANIES

IDENTIFICATION

01 Exact Legal Name of Respondent	02 Year of Report
SOUTHWEST GAS CORPORATION	2011

03 Previous Name and Date of Change *(If name changed during year)*
NOT APPLICABLE

04 Address of Principal Office at End of Year *(Street, City, State, Zip Code)*

5241 SPRING MOUNTAIN ROAD, LAS VEGAS, NEVADA 89150

05 Name of Contact Person	06 Title of Contact Person
GREGORY J. PETERSON	VICE PRESIDENT / CONTROLLER / CAO

07 Address of Contact Person *(Street, City, State, Zip Code)*

5241 SPRING MOUNTAIN ROAD, LAS VEGAS, NEVADA 89150

08 Telephone of Contact Person, Including Area Code	09 This report is:	10 Date of Report (Mo, Da, Yr)
(702) 876-7120	[X] An Original [ ] A Resubmission	

ATTESTATION

The undersigned officer certifies that he/she has examined the accompanying report; that to the best of his/her knowledge, information, and belief, all statements of fact contained in the accompanying report are true and the accompanying report is a correct statement of the business and affairs of the above named respondent in respect to each and every matter set forth therein during the period from and including January 1 to and including December 31 of the year of the report.

11 Name	12 Title
GREGORY J. PETERSON	VICE PRESIDENT / CONTROLLER / CAO
13 Signature	**14 Date Signed**
/S/ GREGORY J. PETERSON	3/29/2012

Title 18, U.S.C. 1001, makes it a crime for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

SELECTED FINANCIAL DATA - CLASS A, B, C AND D GAS UTILITIES

NAME OF UTILITY Southwest Gas Corporation **PHONE** (702) 876-7120

	INCOME STATEMENT DATA (CALIFORNIA INTRASTATE GAS OPERATIONS ONLY) (6)	ANNUAL AMOUNT
26	Operating Revenues	$ 159,940,576
27	Operating and Maintenance	109,802,959
28	Depreciation (5)	16,877,689
29	Depreciation Expense for Asset Retirement Costs	-
30	Amortization and Depletion Expenses and Property Losses	751,853
31	Amortization of Regulatory Assets	30,008
32	Property Taxes (Ad Valorem)	2,547,818
33	Taxes Other than Income and Property Taxes	2,021,256
34	Operating Revenue Deductions (Before Federal & California Income Taxes)	132,031,583
35	Federal and California Income Taxes - Net	8,844,236
36	Gains and Losses from Disposition of Gas Plant - Net	-
37	Accretion Expense	-
38	Total Utility Operating Expenses	140,875,819
39	Net Operating Income (California Intrastate Gas Operations Only)	$ 19,064,757
	OTHER INCOME AND EXPENSE	
40	Net Operating Income from Other Utility Operations (Total)	$ 136,957,691
41	Net Other Income and Deductions	25,096,726
42	Income Before Interest Charges	181,119,174
43	Interest Charges	68,832,025
44	Income Before Extraordinary Items	112,287,149
45	Extraordinary Items - Net of Income Tax	-
46	Net Income (Loss)	112,287,149
47	Preferred Stock Dividend Requirements	-
48	Income Available for Common Stock	112,287,149
49	Common Stock Dividends	49,292,704
	OTHER DATA (CALIFORNIA GAS ONLY)	
50	Payroll Charged to Operating and Maintenance Expense	$ 14,446,939
51	Payroll Capitalized to Gas Utility Plant	$ 1,471,921
52	Total Payroll (4)	$ 15,918,860
53	Total Exploration and Development Expense (accts. 795 through 798)	-
54	Purchased Gas Expense (accts. 807.1 through 807.5)	-
55	Interdepartmental Sales	-
56	Interdepartmental Expenses	-
57	Allowance for Funds Used During Construction	$ 219,192
58	Revenue from Sales to Residential Customers	$ 130,361,215
59	Residential Sales in Mcfs	10,015,510
60	Therms Sold to Residential Customers	101,730,980
61	Total Revenue Sales to Ultimate Customers	$ 163,508,980
62	Mcfs Sold to Ultimate Customers	13,221,929
63	Therms Sold to Ultimate Customers	134,340,680
64	Average Number of Residential Customers	172,633
65	Average Number of Ultimate Customers	181,644

(1) Includes system allocable plant allocated with a four factor rate of 10.35%
(2) 1/1/11 gas plant balances have been restated to reflect the 2011 four factor rate.
(3) Beginning of year, plus end of year, divided by two.
(4) Includes an allocation of administrative payroll based on the four factor.
(5) Includes $ 937,433 of depreciation related to surcharge plant which is separate from gas plant in service.
(6) Some income statement items include allocations for the purpose of this report only, and may not reflect actual amounts applicable to a given rate jurisdiction.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-093 RE: Exhibit No.__(JSG-2), Schedule 1
Witness: Stephen Gaske

Please update the table shown on page 4 of 4, Schedule 1, Exhibit No.__(JSG-2) for 2012.

Response:

Please see Attachment A.

Montana-Dakota Utilities Co.

Bond Yield Averages
January 2012 - November 2012

		[1] 30-Year T-Bonds	[2] Average Corporate	[3] Public Utility Bonds A-Rated	[4] Public Utility Bonds Baa-Rated	[5] Credit Spreads A-Rated	[6] Credit Spreads Baa-Rated
2012	JAN	3.01	4.45	4.34	5.06	1.32	2.05
	FEB	3.11	4.42	4.36	5.02	1.25	1.91
	MAR	3.28	4.54	4.48	5.13	1.20	1.85
	APR	3.18	4.49	4.40	5.11	1.21	1.93
	MAY	2.92	4.33	4.20	4.97	1.28	2.04
	JUN	2.70	4.22	4.08	4.91	1.39	2.21
	JUL	2.60	4.03	3.93	4.85	1.33	2.25
	AUG	2.77	4.09	4.00	4.88	1.23	2.11
	SEP	2.87	4.09	4.02	4.81	1.16	1.94
	OCT	2.91	3.97	3.91	4.54	1.01	1.64
	NOV	2.80	3.92	3.84	4.42	1.04	1.61
2012	AVG	2.92	4.23	4.14	4.88	1.22	1.96

Sources:
[1] Bloomberg Professional, U.S. Government 30-Year Treasury Bond
[2] Bloomberg Professional, Moody's Corporate Average Bond Index
[3] Bloomberg Professional, Moody's A-Rated Utility Bond Index
[4] Bloomberg Professional, Moody's Baa-Rated Utility Bond Index
[5] Equals [3] – [1]
[6] Equals [4] – [1]

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-094 RE: Exhibit No.__(JSG-2), Schedule 2, Page 1 of 9
Witness: Stephen Gaske

Please explain why it would be inappropriate to include WGL Holdings in the comparable gas distribution utility group.

Response:

Page 17 of Exhibit No.___(JSG-1) indicates that I applied the following screening criteria to Value Line's universe of 11 natural gas utilities to arrive at my proxy group:

1. I eliminated any companies that did not have investment-grade bond ratings from either Standard & Poor's or Moody's Investors Service because such companies are not sufficiently comparable in terms of business and financial risk to Montana-Dakota.
2. I excluded any companies that did not pay dividends or that did not have future growth rate estimates provided by both Value Line and Zacks.
3. I eliminated any company that did not derive at least 70 percent of its operating income from regulated natural gas distribution operations in 2011, and that did not have at least 70 percent of its total assets devoted to the provision of natural gas distribution service in 2011.

Based on WGL Holdings, Inc's SEC Form 10-K for the fiscal year ended September 30, 2011, the company only derived 67.58 percent of its operating income from regulated natural gas distribution operations, and therefore fails the third criteria listed above.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-097 RE: Statement F – Rule 38.5.147, page 3
Witness: Jay Skabo

Please provide an electronic copy of page 3 of Statement F- Rule 38.5.147, with all formulas and links intact, including all work papers and associated worksheets.

Response:

Please see Response No. MCC-072.

Consumer Price Index - All Urban Consumers
Original Data Value

Series Id: CUUR0000SA0,CUUS0000SA0
Not Seasonally Adjusted
Area: U.S. city average
Item: All items
Base Period: 1982-84=100
Years: 1973 to 2011

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual	HALF1	HALF2	
1973	42.6	42.9	43.3	43.6	43.9	44.2	44.3	45.1	45.2	45.6	45.9	46.2	44.4			
1974	46.6	47.2	47.8	48.0	48.6	49.0	49.4	50.0	50.6	51.1	51.5	51.9	49.3			11.0%
1975	52.1	52.5	52.7	52.9	53.2	53.6	54.2	54.3	54.6	54.9	55.3	55.5	53.8			9.1%
1976	55.6	55.8	55.9	56.1	56.5	56.8	57.1	57.4	57.6	57.9	58.0	58.2	56.9			5.8%
1977	58.5	59.1	59.5	60.0	60.3	60.7	61.0	61.2	61.4	61.6	61.9	62.1	60.6			6.5%
1978	62.5	62.9	63.4	63.9	64.5	65.2	65.7	66.0	66.5	67.1	67.4	67.7	65.2			7.6%
1979	68.3	69.1	69.8	70.6	71.5	72.3	73.1	73.8	74.6	75.2	75.9	76.7	72.6			11.3%
1980	77.8	78.9	80.1	81.0	81.8	82.7	82.7	83.3	84.0	84.8	85.5	86.3	82.4			13.5%
1981	87.0	87.9	88.5	89.1	89.8	90.6	91.6	92.3	93.2	93.4	93.7	94.0	90.9			10.3%
1982	94.3	94.6	94.5	94.9	95.8	97.0	97.5	97.7	97.9	98.2	98.0	97.6	96.5			6.2%
1983	97.8	97.9	97.9	98.6	99.2	99.5	99.9	100.2	100.7	101.0	101.2	101.3	99.6			3.2%
1984	101.9	102.4	102.6	103.1	103.4	103.7	104.1	104.5	105.0	105.3	105.3	105.3	103.9	102.9	104.9	4.3%
1985	105.5	106.0	106.4	106.9	107.3	107.6	107.8	108.0	108.3	108.7	109.0	109.3	107.6	106.6	108.5	3.6%
1986	109.6	109.3	108.8	108.6	108.9	109.5	109.5	109.7	110.2	110.3	110.4	110.5	109.6	109.1	110.1	1.9%
1987	111.2	111.6	112.1	112.7	113.1	113.5	113.8	114.4	115.0	115.3	115.4	115.4	113.6	112.4	114.9	3.6%
1988	115.7	116.0	116.5	117.1	117.5	118.0	118.5	119.0	119.8	120.2	120.3	120.5	118.3	116.8	119.7	4.1%
1989	121.1	121.6	122.3	123.1	123.8	124.1	124.4	124.6	125.0	125.6	125.9	126.1	124.0	122.7	125.3	4.8%
1990	127.4	128.0	128.7	128.9	129.2	129.9	130.4	131.6	132.7	133.5	133.8	133.8	130.7	128.7	132.6	5.4%
1991	134.6	134.8	135.0	135.2	135.6	136.0	136.2	136.6	137.2	137.4	137.8	137.9	136.2	135.2	137.2	4.2%
1992	138.1	138.6	139.3	139.5	139.7	140.2	140.5	140.9	141.3	141.8	142.0	141.9	140.3	139.2	141.4	3.0%
1993	142.6	143.1	143.6	144.0	144.2	144.4	144.4	144.8	145.1	145.7	145.8	145.8	144.5	143.7	145.3	3.0%
1994	146.2	146.7	147.2	147.4	147.5	148.0	148.4	149.0	149.4	149.5	149.7	149.7	148.2	147.2	149.3	2.6%
1995	150.3	150.9	151.4	151.9	152.2	152.5	152.5	152.9	153.2	153.7	153.6	153.5	152.4	151.5	153.2	2.8%
1996	154.4	154.9	155.7	156.3	156.6	156.7	157.0	157.3	157.8	158.3	158.6	158.6	156.9	155.8	157.9	3.0%
1997	159.1	159.6	160.0	160.2	160.1	160.3	160.5	160.8	161.2	161.6	161.5	161.3	160.5	159.9	161.2	2.3%
1998	161.6	161.9	162.2	162.5	162.8	163.0	163.2	163.4	163.6	164.0	164.0	163.9	163.0	162.3	163.7	1.6%
1999	164.3	164.5	165.0	166.2	166.2	166.2	166.7	167.1	167.9	168.2	168.3	168.3	166.6	165.4	167.8	2.2%
2000	168.8	169.8	171.2	171.3	171.5	172.4	172.8	172.8	173.7	174.0	174.1	174.0	172.2	170.8	173.6	3.4%
2001	175.1	175.8	176.2	176.9	177.7	178.0	177.5	177.5	178.3	177.7	177.4	176.7	177.1	176.6	177.5	2.8%
2002	177.1	177.8	178.8	179.8	179.8	179.9	180.1	180.7	181.0	181.3	181.3	180.9	179.9	178.9	180.9	1.6%
2003	181.7	183.1	184.2	183.8	183.5	183.7	183.9	184.6	185.2	185.0	184.5	184.3	184.0	183.3	184.6	2.3%

Bureau of Labor Statistics

2004	185.2	186.2	187.4	188.0	189.1	189.7	189.4	189.5	189.9	190.9	191.0	190.3	188.9	187.6	190.2	2.7%
2005	190.7	191.8	193.3	194.6	194.4	194.5	195.4	196.4	198.8	199.2	197.6	196.8	195.3	193.2	197.4	3.4%
2006	198.3	198.7	199.8	201.5	202.5	202.9	203.5	203.9	202.9	201.8	201.5	201.8	201.6	200.6	202.6	3.2%
2007	202.416	203.499	205.352	206.686	207.949	208.352	208.299	207.917	208.490	208.936	210.177	210.036	207.342	205.709	208.976	2.8%
2008	211.080	211.693	213.528	214.823	216.632	218.815	219.964	219.086	218.783	216.573	212.425	210.228	215.303	214.429	216.177	3.8%
2009	211.143	212.193	212.709	213.240	213.856	215.693	215.351	215.834	215.969	216.177	216.330	215.949	214.537	213.139	215.935	-0.4%
2010	216.687	216.741	217.631	218.009	218.178	217.965	218.011	218.312	218.439	218.711	218.803	219.179	218.056	217.535	218.576	1.6%
2011	220.223	221.309	223.467	224.906	225.964	225.722	225.922	226.545	226.889	226.421	226.230	225.672	224.939	223.598	226.280	3.2%

Source: Bureau of Labor Statistics

Generated on: December 4, 2012 (01:50:42 PM)

Table 1.1.9. Implicit Price Deflators for Gross Domestic Product

[Index numbers, 2005=100]

Bureau of Economic Analysis

Last Revised on: July 27, 2012 - Next Release Date August 29, 2012

Line		1970	1971	1972	1973	1974	1975	1976
1	**Gross domestic product**	24.338	25.554	26.657	28.136	30.69	33.591	35.519
2	**Personal consumption expenditures**	23.67	24.676	25.52	26.897	29.698	32.179	33.945
3	Goods	35.187	36.245	37.173	39.39	44.306	47.886	49.759
4	Durable goods	56.033	57.968	58.606	59.474	63.379	69.051	72.827
5	Nondurable goods	27.425	28.199	29.103	31.45	36.206	39.004	40.274
6	Services	18.273	19.271	20.089	21.065	22.853	24.82	26.54
7	**Gross private domestic investment**	32.191	33.787	35.201	37.107	40.865	45.839	48.362
8	Fixed investment	31.14	32.708	34.11	35.995	39.54	44.494	47.072
9	Nonresidential	40.531	42.437	43.871	45.56	49.958	56.836	59.988
10	Structures	15.415	16.602	17.796	19.175	21.828	24.443	25.644
11	Equipment and software	60.561	62.36	63.112	64.184	68.917	79.1	83.755
12	Residential	16.666	17.632	18.703	20.359	22.46	24.547	26.124
13	Change in private inventories	---	---	---	---	---	---	---
14	**Net exports of goods and services**	---	---	---	---	---	---	---
15	Exports	34.054	35.31	36.956	41.815	51.517	56.781	58.645
16	Goods	39.186	40.232	41.302	47.937	60.665	67.426	69.15
17	Services	24.165	25.751	28.36	29.68	33.11	35.334	37.468
18	Imports	23.587	25.035	26.789	31.446	44.989	48.733	50.201
19	Goods	24.225	25.467	27.418	32.317	48.36	52.411	53.812
20	Services	20.511	22.368	23.483	27.163	32.303	34.921	36.5
21	**Government consumption expenditures and gross investment**	18.942	20.417	21.986	23.591	25.974	28.581	30.464
22	Federal	19.688	21.371	23.457	25.066	27.299	30.14	32.283
23	National defense	19.116	20.81	23.209	24.911	27.223	29.88	32.058
24	Nondefense	21.107	22.707	23.851	25.188	27.199	30.453	32.494
25	State and local	18.413	19.722	20.898	22.497	24.973	27.412	29.117
	Addendum:							
26	Gross national product	24.32	25.537	26.639	28.121	30.669	33.57	35.502
			5.0%	4.3%	5.5%	9.1%	9.5%	5.7%

6

1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
37.783	40.435	43.798	47.791	52.27	55.459	57.652	59.817	61.628	62.991	64.819	67.046	69.577	72.262
36.155	38.688	42.119	46.642	50.752	53.563	55.868	57.981	59.882	61.341	63.618	66.151	69.025	72.18
52.435	55.653	60.916	67.737	72.77	74.753	76.102	77.541	78.785	78.417	80.939	83.072	86.268	89.801
76.177	80.441	85.773	93.216	99.45	103.329	105.421	106.981	108.112	109.301	112.446	114.301	116.384	117.54
42.582	45.304	50.186	56.344	60.695	62.073	63.138	64.45	65.657	64.818	67.023	69.154	72.584	76.745
28.541	30.759	33.33	36.78	40.444	43.603	46.318	48.729	50.929	53.249	55.409	58.123	60.84	63.808
51.999	56.243	61.341	67.005	73.424	77.16	77.008	77.542	78.33	79.974	81.578	83.421	85.414	86.977
50.767	55.055	60.045	65.663	71.765	75.693	75.574	76.016	76.973	78.813	80.275	82.356	84.35	86.064
64.093	68.386	73.939	80.461	88.229	93.089	92.258	92.035	92.757	94.333	95.181	97.295	99.336	101.238
27.868	30.56	34.11	37.281	42.408	45.755	44.59	44.978	46.046	46.93	47.684	49.709	51.654	53.322
88.731	93.412	99.335	107.819	115.524	120.031	120.284	119.233	119.09	120.976	121.637	123.154	124.695	126.31
28.759	32.281	35.902	39.789	43.036	45.34	46.38	47.713	48.944	50.994	53.079	54.913	56.68	58.011
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61.034	64.753	72.545	79.904	85.81	86.204	86.544	87.348	84.673	83.406	85.516	89.945	91.443	92.063
71.669	75.801	85.807	94.059	100.697	99.545	98.819	99.678	94.691	91.589	93.956	100.006	101.309	100.348
39.579	42.446	45.749	51.38	55.845	59.232	61.553	62.232	63.928	66.007	67.587	68.937	70.783	74.414
54.624	58.482	68.483	85.301	89.887	86.855	83.601	82.879	80.156	80.154	85.008	89.074	91.021	93.63
58.743	62.66	73.888	93.235	98.425	94.449	90.501	89.878	86.342	84.408	90.427	94.734	97.386	99.175
39.093	42.646	48.16	55.892	58.319	58.36	57.404	56.419	56.35	62.45	63.339	66.424	66.071	71.019
32.578	34.664	37.569	41.663	45.761	48.768	50.709	53.31	54.966	55.969	57.532	59.065	60.915	63.395
34.722	36.866	39.704	43.875	48.137	51.405	53.187	56.325	57.602	57.904	58.608	59.849	61.469	63.512
34.486	36.908	39.853	44.179	48.542	51.953	53.775	57.603	58.696	58.642	59.236	60.326	61.882	63.917
34.933	36.452	39.033	42.833	46.837	49.741	51.413	52.69	54.481	55.82	56.856	58.579	60.394	62.462
31.008	33.045	35.979	40.005	43.979	46.791	48.861	51.038	53.006	54.582	56.854	58.626	60.659	63.479
37.767	40.419	43.782	47.769	52.251	55.438	57.635	59.8	61.614	62.973	64.804	67.031	69.57	72.26
6.4%	7.0%	8.3%	9.1%	9.4%	6.1%	4.0%	3.8%	3.0%	2.2%	2.9%	3.4%	3.8%	3.9%

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
74.824	76.598	78.29	79.94	81.606	83.159	84.628	85.584	86.842	88.723	90.727	92.196	94.135	96.786
74.789	76.989	78.679	80.302	82.078	83.864	85.433	86.246	87.636	89.818	91.53	92.778	94.659	97.121
91.996	93.107	93.915	94.87	95.757	96.809	96.696	95.237	95.735	97.655	97.563	96.563	96.493	97.929
119.263	120.087	121.269	123.642	124.544	123.287	120.593	117.181	114.005	111.953	109.733	106.92	103.113	101.124
78.985	80.133	80.784	81.215	82.063	83.922	84.798	84.169	86.268	90.016	90.961	90.888	92.797	96.114
66.581	69.236	71.294	73.2	75.365	77.473	79.812	81.689	83.509	85.818	88.422	90.801	93.686	96.688
88.293	87.969	89.021	90.205	91.207	90.837	90.455	89.454	89.33	90.276	91.053	91.479	92.489	95.644
87.342	87.09	88.163	89.352	90.393	90.149	89.921	89.085	89.028	90.083	90.888	91.261	92.375	95.543
102.804	101.947	102.1	102.592	102.811	101.612	100.326	98.125	96.704	96.75	96.317	95.889	95.471	96.837
54.287	54.298	56.103	58.089	60.6	62.141	64.516	67.48	69.559	72.298	76.087	79.292	82.174	88.441
128.112	126.605	125.322	124.604	123.163	120.2	116.639	111.454	108.195	106.893	104.364	102.24	100.45	99.9
58.771	59.486	61.89	64.068	66.403	67.827	69.556	71.412	74.151	77.415	80.994	83.002	86.953	93.297
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93.284	92.904	92.879	93.914	96.07	94.799	93.174	91.042	90.477	92.07	91.697	91.322	93.282	96.539
100.243	98.635	98.077	99.125	101.478	98.857	96.127	93.095	91.834	92.999	92.423	91.82	93.616	96.958
78.131	80.13	81.142	82.139	83.872	85.491	86.335	86.285	87.314	89.92	90.042	90.202	92.533	95.598
92.849	92.922	92.21	93.075	95.625	93.958	90.692	85.809	86.311	90.027	87.824	86.846	89.851	94.164
97.3	96.767	95.686	96.383	98.952	96.444	92.46	86.875	86.948	91.205	88.557	87.004	89.541	93.895
73.612	75.673	76.313	77.806	80.235	82.235	82.233	80.628	83.185	84.209	84.219	86.089	91.469	95.573
65.596	67.266	68.938	70.808	72.742	74.477	75.854	76.879	79.337	82.513	84.764	87.003	90.65	94.53
66.032	68.062	69.79	71.683	73.674	75.719	77.047	77.931	79.886	82.524	84.201	87.318	91.024	95.335
66.222	68.522	69.712	71.438	73.161	75.431	76.517	77.328	79.225	81.821	83.484	86.624	90.659	94.895
65.561	66.92	69.883	72.144	74.703	76.276	78.095	79.12	81.188	83.907	85.612	88.689	91.774	96.234
65.448	66.862	68.499	70.357	72.258	73.812	75.219	76.32	79.036	82.482	85.019	86.81	90.425	94.062
74.819	76.586	78.291	79.942	81.611	83.166	84.63	85.581	86.84	88.72	90.725	92.191	94.131	96.782
3.5%	2.4%	2.2%	2.1%	2.1%	1.9%	1.8%	1.1%	1.5%	2.2%	2.3%	1.6%	2.1%	2.8%

2005	2006	2007	2008	2009	2010	2011
100	103.231	106.227	108.582	109.529	110.993	113.359
100	102.723	105.499	108.943	109.004	111.087	113.79
100	101.441	102.764	105.912	103.105	104.852	108.822
100	98.361	96.43	94.628	92.83	91.611	90.799
100	103.23	106.49	112.567	109.177	112.621	119.43
100	103.415	106.981	110.584	112.157	114.418	116.435
100	104.27	106.285	107.621	106.252	104.782	106.362
100	104.347	106.36	107.587	106.318	105.024	106.68
100	103.425	105.645	107.717	107.102	105.514	107.359
100	112.922	119.78	125.706	122.527	121.158	126.85
100	100.049	100.525	101	101.477	99.806	100.445
100	106.081	107.612	106.296	102.713	102.519	103.406
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100	103.441	106.901	111.975	105.924	110.739	117.86
100	103.319	106.793	112.143	104.528	109.828	118.182
100	103.719	107.146	111.574	109.002	112.741	116.972
100	104.131	107.785	119.237	106.598	112.989	121.851
100	104.192	107.792	120.254	105.379	112.52	122.482
100	103.806	107.75	114.006	111.769	114.714	118.126
100	104.842	109.863	115.245	114.592	117.334	121.233
100	104.107	107.753	111.225	110.959	113.583	116.721
100	104.421	108.249	112.187	111.347	113.951	117.411
100	103.468	106.743	109.24	110.177	112.843	115.337
100	105.276	111.112	117.666	116.763	119.579	124.001
100	103.234	106.23	108.589	109.529	110.977	113.353
3.3%	3.2%	2.9%	2.2%	0.9%	1.3%	2.1%

6

Gross Domestic Product
Percent change from preceding period

7/27/12

Annual			Quarterly (Seasonally adjusted annual rates)		
	GDP percent change based on current dollars	GDP percent change based on chained 2005 dollars		GDP percent change based on current dollars	GDP percent change based on chained 2005 dollars
1930	-12.0	-8.6	1947q2	5.6	-0.6
1931	-16.1	-6.5	1947q3	7.0	-0.3
1932	-23.2	-13.1	1947q4	17.1	6.2
1933	-3.9	-1.3	1948q1	9.7	6.5
1934	17.0	10.9	1948q2	11.1	7.5
1935	11.1	8.9	1948q3	10.1	2.2
1936	14.3	13.1	1948q4	1.9	0.6
1937	9.7	5.1	1949q1	-7.3	-5.5
1938	-6.3	-3.4	1949q2	-5.4	-1.4
1939	7.0	8.1	1949q3	2.2	4.6
1940	10.0	8.8	1949q4	-3.6	-3.7
1941	25.0	17.1	1950q1	16.0	17.2
1942	27.7	18.5	1950q2	14.3	12.7
1943	22.7	16.4	1950q3	26.8	16.6
1944	10.7	8.1	1950q4	16.0	7.2
1945	1.5	-1.1	1951q1	21.5	5.1
1946	-0.4	-10.9	1951q2	9.6	6.8
1947	9.8	-0.9	1951q3	8.4	8.2
1948	10.3	4.4	1951q4	5.2	0.7
1949	-0.7	-0.5	1952q1	3.8	4.1
1950	9.9	8.7	1952q2	1.1	0.4
1951	15.5	7.7	1952q3	7.4	2.7
1952	5.6	3.8	1952q4	15.1	13.9
1953	5.9	4.6	1953q1	7.8	7.7
1954	0.3	-0.6	1953q2	3.9	3.1
1955	9.0	7.2	1953q3	-0.9	-2.4
1956	5.5	2.0	1953q4	-5.4	-6.2
1957	5.4	2.0	1954q1	-0.7	-1.9
1958	1.3	-0.9	1954q2	0.8	0.5
1959	8.4	7.2	1954q3	5.2	4.6
1960	3.9	2.5	1954q4	9.4	8.3
1961	3.5	2.3	1955q1	14.2	12.0
1962	7.5	6.1	1955q2	8.5	6.8
1963	5.5	4.4	1955q3	8.6	5.5
1964	7.4	5.8	1955q4	6.4	2.2
1965	8.4	6.4	1956q1	2.2	-1.8
1966	9.5	6.5	1956q2	5.6	3.2
1967	5.7	2.5	1956q3	4.7	-0.5
1968	9.3	4.8	1956q4	8.3	6.7
1969	8.2	3.1	1957q1	8.4	2.5
1970	5.5	0.2	1957q2	1.8	-1.0

1971	8.5	3.4
1972	9.9	5.3
1973	11.7	5.8
1974	8.5	-0.6
1975	9.2	-0.2
1976	11.4	5.4
1977	11.3	4.6
1978	13.0	5.6
1979	11.7	3.1
1980	8.8	-0.3
1981	12.1	2.5
1982	4.0	-1.9
1983	8.7	4.5
1984	11.2	7.2
1985	7.3	4.1
1986	5.8	3.5
1987	6.2	3.2
1988	7.7	4.1
1989	7.5	3.6
1990	5.8	1.9
1991	3.3	-0.2
1992	5.8	3.4
1993	5.1	2.9
1994	6.3	4.1
1995	4.7	2.5
1996	5.7	3.7
1997	6.3	4.5
1998	5.5	4.4
1999	6.4	4.8
2000	6.4	4.1
2001	3.4	1.1
2002	3.5	1.8
2003	4.7	2.5
2004	6.4	3.5
2005	6.5	3.1
2006	6.0	2.7
2007	4.9	1.9
2008	1.9	-0.3
2009	-2.2	-3.1
2010	3.8	2.4
2011	4.0	1.8

1957q3	6.4	3.9
1957q4	-4.1	-4.1
1958q1	-6.4	-10.4
1958q2	3.7	2.5
1958q3	12.5	9.7
1958q4	11.7	9.7
1959q1	8.9	8.3
1959q2	10.9	10.5
1959q3	0.7	-0.5
1959q4	3.1	1.4
1960q1	11.1	9.3
1960q2	-0.6	-1.9
1960q3	2.1	0.7
1960q4	-4.0	-5.0
1961q1	3.3	2.4
1961q2	8.7	7.7
1961q3	8.0	6.6
1961q4	9.9	8.4
1962q1	9.9	7.4
1962q2	5.1	4.5
1962q3	4.7	3.7
1962q4	2.3	1.0
1963q1	6.3	5.3
1963q2	5.9	5.1
1963q3	8.6	7.7
1963q4	6.2	3.1
1964q1	10.6	9.3
1964q2	5.8	4.7
1964q3	7.2	5.5
1964q4	3.1	1.1
1965q1	12.4	10.2
1965q2	7.4	5.5
1965q3	10.0	8.4
1965q4	12.9	10.0
1966q1	13.1	10.2
1966q2	4.8	1.3
1966q3	7.0	2.7
1966q4	7.1	3.3
1967q1	5.5	3.6
1967q2	2.2	0.1
1967q3	7.3	3.2
1967q4	7.7	3.1
1968q1	13.3	8.5
1968q2	11.5	7.0
1968q3	6.9	2.8
1968q4	7.6	1.7
1969q1	11.0	6.5
1969q2	6.5	1.2
1969q3	8.5	2.6
1969q4	3.3	-1.9
1970q1	5.1	-0.6
1970q2	6.4	0.7
1970q3	6.9	3.6
1970q4	0.8	-4.2
1971q1	18.4	11.5
1971q2	7.8	2.3

1971q3	7.5	3.2
1971q4	4.4	1.1
1972q1	14.2	7.3
1972q2	12.4	9.8
1972q3	8.0	3.9
1972q4	12.5	6.8
1973q1	16.0	10.6
1973q2	11.3	4.7
1973q3	5.7	-2.1
1973q4	12.4	3.9
1974q1	4.2	-3.5
1974q2	11.0	1.0
1974q3	8.0	-3.9
1974q4	10.7	-1.6
1975q1	4.4	-4.8
1975q2	9.4	3.1
1975q3	15.1	6.9
1975q4	13.0	5.3
1976q1	14.2	9.4
1976q2	7.5	3.0
1976q3	7.6	2.0
1976q4	10.6	2.9
1977q1	12.0	4.7
1977q2	14.5	8.2
1977q3	12.7	7.4
1977q4	9.0	-0.1
1978q1	7.4	1.4
1978q2	25.5	16.7
1978q3	11.1	4.0
1978q4	14.6	5.4
1979q1	8.1	0.7
1979q2	10.7	0.4
1979q3	12.1	2.9
1979q4	9.5	1.1
1980q1	10.1	1.3
1980q2	0.6	-7.9
1980q3	8.6	-0.7
1980q4	20.0	7.6
1981q1	20.0	8.6
1981q2	4.4	-3.2
1981q3	12.6	4.9
1981q4	2.2	-4.9
1982q1	-1.2	-6.4
1982q2	7.2	2.2
1982q3	4.2	-1.5
1982q4	4.7	0.3
1983q1	8.5	5.1
1983q2	12.5	9.3
1983q3	12.6	8.1
1983q4	11.8	8.5
1984q1	13.6	8.0
1984q2	10.8	7.1
1984q3	7.3	3.9
1984q4	6.0	3.3
1985q1	8.5	3.8
1985q2	5.8	3.4

1985q3	8.2	6.4
1985q4	5.8	3.1
1986q1	6.0	3.9
1986q2	3.8	1.6
1986q3	6.3	3.9
1986q4	4.7	1.9
1987q1	6.1	2.2
1987q2	6.7	4.3
1987q3	6.8	3.5
1987q4	10.3	7.0
1988q1	5.5	2.1
1988q2	9.2	5.2
1988q3	6.8	2.1
1988q4	8.7	5.5
1989q1	8.6	3.8
1989q2	7.1	3.0
1989q3	5.9	3.2
1989q4	3.6	0.9
1990q1	9.4	4.2
1990q2	6.4	1.6
1990q3	3.7	0.0
1990q4	-0.3	-3.5
1991q1	2.4	-1.9
1991q2	5.7	2.7
1991q3	4.9	1.7
1991q4	4.0	1.6
1992q1	6.6	4.5
1992q2	6.9	4.3
1992q3	6.1	4.2
1992q4	6.7	4.3
1993q1	3.2	0.7
1993q2	4.9	2.6
1993q3	4.0	2.1
1993q4	7.7	5.4
1994q1	6.2	4.0
1994q2	7.6	5.6
1994q3	5.1	2.6
1994q4	6.7	4.5
1995q1	3.3	1.0
1995q2	2.7	0.9
1995q3	5.4	3.4
1995q4	4.9	2.8
1996q1	5.2	2.8
1996q2	8.7	7.1
1996q3	4.8	3.5
1996q4	6.8	4.4
1997q1	5.8	3.1
1997q2	7.1	6.1
1997q3	6.6	5.1
1997q4	4.6	3.1
1998q1	4.5	3.8
1998q2	4.6	3.6
1998q3	7.0	5.4
1998q4	8.4	7.1
1999q1	5.5	3.6
1999q2	4.6	3.2

1999q3	6.8	5.2
1999q4	8.9	7.4
2000q1	4.3	1.1
2000q2	10.2	8.0
2000q3	2.8	0.3
2000q4	4.6	2.4
2001q1	1.4	-1.3
2001q2	5.5	2.7
2001q3	0.2	-1.1
2001q4	2.7	1.4
2002q1	4.9	3.5
2002q2	4.0	2.1
2002q3	3.8	2.0
2002q4	2.5	0.1
2003q1	4.5	1.7
2003q2	4.6	3.4
2003q3	9.1	6.7
2003q4	5.8	3.7
2004q1	6.3	2.7
2004q2	6.1	2.6
2004q3	6.0	3.0
2004q4	6.4	3.3
2005q1	8.1	4.2
2005q2	4.5	1.8
2005q3	7.5	3.2
2005q4	5.5	2.1
2006q1	8.3	5.1
2006q2	5.2	1.6
2006q3	3.1	0.1
2006q4	4.6	2.7
2007q1	5.2	0.5
2007q2	6.5	3.6
2007q3	4.3	3.0
2007q4	3.6	1.7
2008q1	0.6	-1.8
2008q2	4.0	1.3
2008q3	-0.6	-3.7
2008q4	-8.4	-8.9
2009q1	-4.4	-5.3
2009q2	-1.1	-0.3
2009q3	1.9	1.4
2009q4	5.3	4.0
2010q1	3.9	2.3
2010q2	4.1	2.2
2010q3	4.6	2.6
2010q4	4.5	2.4
2011q1	2.2	0.1
2011q2	5.2	2.5
2011q3	4.3	1.3
2011q4	4.2	4.1
2012q1	4.2	2.0
2012q2	3.1	1.5

Current-Dollar and "Real" Gross Domestic Product 7/27/12

Annual			Quarterly (Seasonally adjusted annual rates)		
	GDP in billions of current dollars	GDP in billions of chained 2005 dollars		GDP in billions of current dollars	GDP in billions of chained 2005 dollars
1929	103.6	976.1	1947q1	237.2	1,770.7
1930	91.2	892.0	1947q2	240.4	1,768.0
1931	76.5	834.2	1947q3	244.5	1,766.5
1932	58.7	725.2	1947q4	254.3	1,793.3
1933	56.4	715.8	1948q1	260.3	1,821.8
1934	66.0	793.7	1948q2	267.3	1,855.3
1935	73.3	864.2	1948q3	273.8	1,865.3
1936	83.8	977.0	1948q4	275.1	1,868.2
1937	91.9	1,027.1	1949q1	269.9	1,842.2
1938	86.1	991.8	1949q2	266.2	1,835.5
1939	92.2	1,071.9	1949q3	267.6	1,856.1
1940	101.4	1,165.9	1949q4	265.2	1,838.7
1941	126.7	1,365.0	1950q1	275.2	1,913.0
1942	161.9	1,616.8	1950q2	284.5	1,971.2
1943	198.6	1,881.5	1950q3	301.9	2,048.4
1944	219.8	2,033.5	1950q4	313.3	2,084.4
1945	223.0	2,010.7	1951q1	329.0	2,110.7
1946	222.2	1,790.7	1951q2	336.6	2,145.7
1947	244.1	1,774.6	1951q3	343.5	2,188.5
1948	269.1	1,852.7	1951q4	347.9	2,192.2
1949	267.2	1,843.1	1952q1	351.2	2,214.3
1950	293.7	2,004.2	1952q2	352.1	2,216.7
1951	339.3	2,159.3	1952q3	358.5	2,231.6
1952	358.3	2,242.0	1952q4	371.4	2,305.3
1953	379.3	2,345.2	1953q1	378.4	2,348.4
1954	380.4	2,330.4	1953q2	382.0	2,366.2
1955	414.7	2,498.2	1953q3	381.1	2,351.8
1956	437.4	2,547.6	1953q4	375.9	2,314.6
1957	461.1	2,598.8	1954q1	375.2	2,303.5
1958	467.2	2,575.4	1954q2	376.0	2,306.4
1959	506.6	2,760.1	1954q3	380.8	2,332.4
1960	526.4	2,828.5	1954q4	389.4	2,379.1
1961	544.8	2,894.4	1955q1	402.6	2,447.7
1962	585.7	3,069.8	1955q2	410.9	2,488.1
1963	617.8	3,204.0	1955q3	419.4	2,521.4
1964	663.6	3,389.4	1955q4	426.0	2,535.5
1965	719.1	3,607.0	1956q1	428.3	2,523.9
1966	787.7	3,842.1	1956q2	434.2	2,543.8
1967	832.4	3,939.2	1956q3	439.2	2,540.6
1968	909.8	4,129.9	1956q4	448.1	2,582.1
1969	984.4	4,258.2	1957q1	457.2	2,597.9
1970	1,038.3	4,266.3	1957q2	459.2	2,591.7
1971	1,126.8	4,409.5	1957q3	466.4	2,616.6
1972	1,237.9	4,643.8	1957q4	461.5	2,589.1
1973	1,382.3	4,912.8	1958q1	453.9	2,519.0

1974	1,499.5	4,885.7
1975	1,637.7	4,875.4
1976	1,824.6	5,136.9
1977	2,030.1	5,373.1
1978	2,293.8	5,672.8
1979	2,562.2	5,850.1
1980	2,788.1	5,834.0
1981	3,126.8	5,982.1
1982	3,253.2	5,865.9
1983	3,534.6	6,130.9
1984	3,930.9	6,571.5
1985	4,217.5	6,843.4
1986	4,460.1	7,080.5
1987	4,736.4	7,307.0
1988	5,100.4	7,607.4
1989	5,482.1	7,879.2
1990	5,800.5	8,027.1
1991	5,992.1	8,008.3
1992	6,342.3	8,280.0
1993	6,667.4	8,516.2
1994	7,085.2	8,863.1
1995	7,414.7	9,086.0
1996	7,838.5	9,425.8
1997	8,332.4	9,845.9
1998	8,793.5	10,274.7
1999	9,353.5	10,770.7
2000	9,951.5	11,216.4
2001	10,286.2	11,337.5
2002	10,642.3	11,543.1
2003	11,142.2	11,836.4
2004	11,853.3	12,246.9
2005	12,623.0	12,623.0
2006	13,377.2	12,958.5
2007	14,028.7	13,206.4
2008	14,291.5	13,161.9
2009	13,973.7	12,757.9
2010	14,498.9	13,063.0
2011	15,075.7	13,299.1

1958q2	458.0	2,534.5
1958q3	471.7	2,593.9
1958q4	485.0	2,654.3
1959q1	495.5	2,708.0
1959q2	508.5	2,776.4
1959q3	509.3	2,773.1
1959q4	513.2	2,782.8
1960q1	527.0	2,845.3
1960q2	526.2	2,832.0
1960q3	529.0	2,836.6
1960q4	523.7	2,800.2
1961q1	528.0	2,816.9
1961q2	539.0	2,869.6
1961q3	549.5	2,915.9
1961q4	562.6	2,975.3
1962q1	576.1	3,028.7
1962q2	583.2	3,062.1
1962q3	590.0	3,090.4
1962q4	593.3	3,097.9
1963q1	602.5	3,138.4
1963q2	611.2	3,177.7
1963q3	623.9	3,237.6
1963q4	633.5	3,262.2
1964q1	649.6	3,335.4
1964q2	658.9	3,373.7
1964q3	670.5	3,419.5
1964q4	675.6	3,429.0
1965q1	695.7	3,513.3
1965q2	708.1	3,560.9
1965q3	725.2	3,633.2
1965q4	747.5	3,720.8
1966q1	770.8	3,812.2
1966q2	779.9	3,824.9
1966q3	793.1	3,850.0
1966q4	806.9	3,881.2
1967q1	817.8	3,915.4
1967q2	822.3	3,916.2
1967q3	837.0	3,947.5
1967q4	852.7	3,977.6
1968q1	879.8	4,059.5
1968q2	904.1	4,128.5
1968q3	919.3	4,156.7
1968q4	936.2	4,174.7
1969q1	960.9	4,240.5
1969q2	976.1	4,252.8
1969q3	996.3	4,279.7
1969q4	1,004.5	4,259.6
1970q1	1,017.1	4,252.9
1970q2	1,033.1	4,260.7
1970q3	1,050.5	4,298.6
1970q4	1,052.7	4,253.0
1971q1	1,098.1	4,370.3
1971q2	1,118.8	4,395.1
1971q3	1,139.1	4,430.2
1971q4	1,151.4	4,442.5
1972q1	1,190.1	4,521.9
1972q2	1,225.6	4,629.1

1972q3	1,249.3	4,673.5
1972q4	1,286.6	4,750.5
1973q1	1,335.1	4,872.0
1973q2	1,371.5	4,928.4
1973q3	1,390.7	4,902.1
1973q4	1,431.8	4,948.8
1974q1	1,446.5	4,905.4
1974q2	1,484.8	4,918.0
1974q3	1,513.7	4,869.4
1974q4	1,552.8	4,850.2
1975q1	1,569.4	4,791.2
1975q2	1,605.0	4,827.8
1975q3	1,662.4	4,909.1
1975q4	1,713.9	4,973.3
1976q1	1,771.9	5,086.3
1976q2	1,804.2	5,124.6
1976q3	1,837.7	5,149.7
1976q4	1,884.5	5,187.1
1977q1	1,938.5	5,247.3
1977q2	2,005.2	5,351.6
1977q3	2,066.0	5,447.3
1977q4	2,110.8	5,446.1
1978q1	2,149.1	5,464.7
1978q2	2,274.7	5,679.7
1978q3	2,335.2	5,735.4
1978q4	2,416.0	5,811.3
1979q1	2,463.3	5,821.0
1979q2	2,526.4	5,826.4
1979q3	2,599.7	5,868.3
1979q4	2,659.4	5,884.5
1980q1	2,724.1	5,903.4
1980q2	2,728.0	5,782.4
1980q3	2,785.2	5,771.7
1980q4	2,915.3	5,878.4
1981q1	3,051.4	6,000.6
1981q2	3,084.3	5,952.7
1981q3	3,177.0	6,025.0
1981q4	3,194.7	5,950.0
1982q1	3,184.9	5,852.3
1982q2	3,240.9	5,884.0
1982q3	3,274.4	5,861.4
1982q4	3,312.5	5,866.0
1983q1	3,381.0	5,938.9
1983q2	3,482.2	6,072.4
1983q3	3,587.1	6,192.2
1983q4	3,688.1	6,320.2
1984q1	3,807.4	6,442.8
1984q2	3,906.3	6,554.0
1984q3	3,976.0	6,617.7
1984q4	4,034.0	6,671.6
1985q1	4,117.2	6,734.5
1985q2	4,175.7	6,791.5
1985q3	4,258.3	6,897.6
1985q4	4,318.7	6,950.0
1986q1	4,382.4	7,016.8
1986q2	4,423.2	7,045.0
1986q3	4,491.3	7,112.9

1986q4	4,543.3	7,147.3
1987q1	4,611.1	7,186.9
1987q2	4,686.7	7,263.3
1987q3	4,764.5	7,326.3
1987q4	4,883.1	7,451.7
1988q1	4,948.6	7,490.2
1988q2	5,059.3	7,586.4
1988q3	5,142.8	7,625.6
1988q4	5,251.0	7,727.4
1989q1	5,360.3	7,799.9
1989q2	5,453.6	7,858.3
1989q3	5,532.9	7,920.6
1989q4	5,581.7	7,937.9
1990q1	5,708.1	8,020.8
1990q2	5,797.4	8,052.7
1990q3	5,850.6	8,052.6
1990q4	5,846.0	7,982.0
1991q1	5,880.2	7,943.4
1991q2	5,962.0	7,997.0
1991q3	6,033.7	8,030.7
1991q4	6,092.5	8,062.2
1992q1	6,190.7	8,150.7
1992q2	6,295.2	8,237.3
1992q3	6,389.7	8,322.3
1992q4	6,493.6	8,409.8
1993q1	6,544.5	8,425.3
1993q2	6,622.7	8,479.2
1993q3	6,688.3	8,523.8
1993q4	6,813.8	8,636.4
1994q1	6,916.3	8,720.5
1994q2	7,044.3	8,839.8
1994q3	7,131.8	8,896.7
1994q4	7,248.2	8,995.5
1995q1	7,307.7	9,017.6
1995q2	7,355.8	9,037.0
1995q3	7,452.5	9,112.9
1995q4	7,542.5	9,176.4
1996q1	7,638.2	9,239.3
1996q2	7,800.0	9,399.0
1996q3	7,892.7	9,480.8
1996q4	8,023.0	9,584.3
1997q1	8,137.0	9,658.0
1997q2	8,276.8	9,801.2
1997q3	8,409.9	9,924.2
1997q4	8,505.7	10,000.3
1998q1	8,600.6	10,094.8
1998q2	8,698.6	10,185.6
1998q3	8,847.2	10,320.0
1998q4	9,027.5	10,498.6
1999q1	9,148.6	10,592.1
1999q2	9,252.6	10,674.9
1999q3	9,405.1	10,810.7
1999q4	9,607.7	11,004.8
2000q1	9,709.5	11,033.6
2000q2	9,949.1	11,248.8
2000q3	10,017.5	11,258.3
2000q4	10,129.8	11,325.0

2001q1	10,165.1	11,287.8
2001q2	10,301.3	11,361.7
2001q3	10,305.2	11,330.4
2001q4	10,373.1	11,370.0
2002q1	10,498.7	11,467.1
2002q2	10,601.9	11,528.1
2002q3	10,701.7	11,586.6
2002q4	10,766.9	11,590.6
2003q1	10,887.4	11,638.9
2003q2	11,011.6	11,737.5
2003q3	11,255.1	11,930.7
2003q4	11,414.8	12,038.6
2004q1	11,589.9	12,117.9
2004q2	11,762.9	12,195.9
2004q3	11,936.3	12,286.7
2004q4	12,123.9	12,387.2
2005q1	12,361.8	12,515.0
2005q2	12,500.0	12,570.7
2005q3	12,728.6	12,670.5
2005q4	12,901.4	12,735.6
2006q1	13,161.4	12,896.4
2006q2	13,330.4	12,948.7
2006q3	13,432.8	12,950.4
2006q4	13,584.2	13,038.4
2007q1	13,758.5	13,056.1
2007q2	13,976.8	13,173.6
2007q3	14,126.2	13,269.8
2007q4	14,253.2	13,326.0
2008q1	14,273.9	13,266.8
2008q2	14,415.5	13,310.5
2008q3	14,395.1	13,186.9
2008q4	14,081.7	12,883.5
2009q1	13,923.4	12,711.0
2009q2	13,885.4	12,701.0
2009q3	13,952.2	12,746.7
2009q4	14,133.6	12,873.1
2010q1	14,270.3	12,947.6
2010q2	14,413.5	13,019.6
2010q3	14,576.0	13,103.5
2010q4	14,735.9	13,181.2
2011q1	14,814.9	13,183.8
2011q2	15,003.6	13,264.7
2011q3	15,163.2	13,306.9
2011q4	15,321.0	13,441.0
2012q1	15,478.3	13,506.4
2012q2	15,595.9	13,558.0

		30-Year T-Bonds				Average Corporate				Public Utility Bonds (A-Rated)			
		Date	Yield			Date	Yield			Date	Yield		
1	2007	1/1/2007	4.8096	1	2007	1/2/2007	5.88	1	2007	1/2/2007	5.92	1	2007
1	2007	1/2/2007	4.7847	1	2007	1/3/2007	5.85	1	2007	1/3/2007	5.88	1	2007
1	2007	1/3/2007	4.7631	1	2007	1/4/2007	5.81	1	2007	1/4/2007	5.84	1	2007
1	2007	1/4/2007	4.7079	1	2007	1/5/2007	5.82	1	2007	1/5/2007	5.85	1	2007
1	2007	1/5/2007	4.7385	1	2007	1/8/2007	5.82	1	2007	1/8/2007	5.85	1	2007
1	2007	1/8/2007	4.7334	1	2007	1/9/2007	5.82	1	2007	1/9/2007	5.85	1	2007
1	2007	1/9/2007	4.7375	1	2007	1/10/2007	5.85	1	2007	1/10/2007	5.88	1	2007
1	2007	1/10/2007	4.7745	1	2007	1/11/2007	5.9	1	2007	1/11/2007	5.93	1	2007
1	2007	1/11/2007	4.8181	1	2007	1/12/2007	5.94	1	2007	1/12/2007	5.97	1	2007
1	2007	1/12/2007	4.86	1	2007	1/16/2007	5.92	1	2007	1/16/2007	5.95	1	2007
1	2007	1/15/2007	4.86	1	2007	1/17/2007	5.96	1	2007	1/17/2007	5.99	1	2007
1	2007	1/16/2007	4.8401	1	2007	1/18/2007	5.92	1	2007	1/18/2007	5.95	1	2007
1	2007	1/17/2007	4.8706	1	2007	1/19/2007	5.93	1	2007	1/19/2007	5.97	1	2007
1	2007	1/18/2007	4.8401	1	2007	1/22/2007	5.92	1	2007	1/22/2007	5.95	1	2007
1	2007	1/19/2007	4.8623	1	2007	1/23/2007	5.97	1	2007	1/23/2007	6	1	2007
1	2007	1/22/2007	4.8476	1	2007	1/24/2007	5.97	1	2007	1/24/2007	6.01	1	2007
1	2007	1/23/2007	4.9057	1	2007	1/25/2007	6.02	1	2007	1/25/2007	6.05	1	2007
1	2007	1/24/2007	4.9099	1	2007	1/26/2007	6.04	1	2007	1/26/2007	6.07	1	2007
1	2007	1/25/2007	4.9667	1	2007	1/29/2007	6.05	1	2007	1/29/2007	6.08	1	2007
1	2007	1/26/2007	4.9722	1	2007	1/30/2007	6.04	1	2007	1/30/2007	6.06	1	2007
1	2007	1/29/2007	4.995	1	2007	1/31/2007	5.99	1	2007	1/31/2007	6.01	1	2007
1	2007	1/30/2007	4.9777	2	2007	2/1/2007	6	2	2007	2/1/2007	6.02	2	2007
1	2007	1/31/2007	4.9069	2	2007	2/2/2007	5.99	2	2007	2/2/2007	6.01	2	2007
2	2007	2/1/2007	4.9294	2	2007	2/5/2007	5.97	2	2007	2/5/2007	5.98	2	2007
2	2007	2/2/2007	4.922	2	2007	2/6/2007	5.92	2	2007	2/6/2007	5.94	2	2007
2	2007	2/5/2007	4.9071	2	2007	2/7/2007	5.9	2	2007	2/7/2007	5.92	2	2007
2	2007	2/6/2007	4.8679	2	2007	2/8/2007	5.89	2	2007	2/8/2007	5.91	2	2007
2	2007	2/7/2007	4.8521	2	2007	2/9/2007	5.94	2	2007	2/9/2007	5.96	2	2007
2	2007	2/8/2007	4.8396	2	2007	2/12/2007	5.95	2	2007	2/12/2007	5.97	2	2007
2	2007	2/9/2007	4.8635	2	2007	2/13/2007	5.97	2	2007	2/13/2007	5.99	2	2007
2	2007	2/12/2007	4.8857	2	2007	2/14/2007	5.89	2	2007	2/14/2007	5.91	2	2007
2	2007	2/13/2007	4.8989	2	2007	2/15/2007	5.87	2	2007	2/15/2007	5.89	2	2007
2	2007	2/14/2007	4.8333	2	2007	2/16/2007	5.85	2	2007	2/16/2007	5.87	2	2007
2	2007	2/15/2007	4.8054	2	2007	2/20/2007	5.84	2	2007	2/20/2007	5.86	2	2007
2	2007	2/16/2007	4.7875	2	2007	2/21/2007	5.85	2	2007	2/21/2007	5.87	2	2007
2	2007	2/19/2007	4.7874	2	2007	2/22/2007	5.88	2	2007	2/22/2007	5.9	2	2007
2	2007	2/20/2007	4.7765	2	2007	2/23/2007	5.83	2	2007	2/23/2007	5.85	2	2007
2	2007	2/21/2007	4.7904	2	2007	2/26/2007	5.78	2	2007	2/26/2007	5.8	2	2007
2	2007	2/22/2007	4.8293	2	2007	2/27/2007	5.69	2	2007	2/27/2007	5.7	2	2007
2	2007	2/23/2007	4.7765	2	2007	2/28/2007	5.76	2	2007	2/28/2007	5.78	2	2007

2	2007	2/26/2007	4.7303	3	2007	3/1/2007	5.77	3	2007	3/1/2007	5.8	3	2007
2	2007	2/27/2007	4.6316	3	2007	3/2/2007	5.75	3	2007	3/2/2007	5.77	3	2007
2	2007	2/28/2007	4.6806	3	2007	3/5/2007	5.77	3	2007	3/5/2007	5.79	3	2007
3	2007	3/1/2007	4.6758	3	2007	3/6/2007	5.77	3	2007	3/6/2007	5.79	3	2007
3	2007	3/2/2007	4.6382	3	2007	3/7/2007	5.75	3	2007	3/7/2007	5.77	3	2007
3	2007	3/5/2007	4.6344	3	2007	3/8/2007	5.76	3	2007	3/8/2007	5.78	3	2007
3	2007	3/6/2007	4.6584	3	2007	3/9/2007	5.83	3	2007	3/9/2007	5.85	3	2007
3	2007	3/7/2007	4.6286	3	2007	3/12/2007	5.8	3	2007	3/12/2007	5.81	3	2007
3	2007	3/8/2007	4.6545	3	2007	3/13/2007	5.77	3	2007	3/13/2007	5.79	3	2007
3	2007	3/9/2007	4.7214	3	2007	3/14/2007	5.81	3	2007	3/14/2007	5.82	3	2007
3	2007	3/12/2007	4.697	3	2007	3/15/2007	5.81	3	2007	3/15/2007	5.82	3	2007
3	2007	3/13/2007	4.6564	3	2007	3/16/2007	5.82	3	2007	3/16/2007	5.82	3	2007
3	2007	3/14/2007	4.6989	3	2007	3/19/2007	5.84	3	2007	3/19/2007	5.85	3	2007
3	2007	3/15/2007	4.695	3	2007	3/20/2007	5.83	3	2007	3/20/2007	5.83	3	2007
3	2007	3/16/2007	4.6931	3	2007	3/21/2007	5.82	3	2007	3/21/2007	5.82	3	2007
3	2007	3/19/2007	4.7135	3	2007	3/22/2007	5.91	3	2007	3/22/2007	5.91	3	2007
3	2007	3/20/2007	4.7115	3	2007	3/23/2007	5.92	3	2007	3/23/2007	5.93	3	2007
3	2007	3/21/2007	4.7203	3	2007	3/26/2007	5.91	3	2007	3/26/2007	5.91	3	2007
3	2007	3/22/2007	4.7744	3	2007	3/27/2007	5.94	3	2007	3/27/2007	5.94	3	2007
3	2007	3/23/2007	4.8022	3	2007	3/28/2007	5.96	3	2007	3/28/2007	5.96	3	2007
3	2007	3/26/2007	4.8002	3	2007	3/29/2007	5.96	3	2007	3/29/2007	5.95	3	2007
3	2007	3/27/2007	4.7982	3	2007	3/30/2007	5.98	3	2007	3/30/2007	5.97	3	2007
3	2007	3/28/2007	4.8311	4	2007	4/2/2007	5.97	4	2007	4/2/2007	5.95	4	2007
3	2007	3/29/2007	4.8432	4	2007	4/3/2007	5.98	4	2007	4/3/2007	5.96	4	2007
3	2007	3/30/2007	4.8432	4	2007	4/4/2007	5.98	4	2007	4/4/2007	5.96	4	2007
4	2007	4/2/2007	4.8361	4	2007	4/5/2007	6.01	4	2007	4/5/2007	5.99	4	2007
4	2007	4/3/2007	4.8482	4	2007	4/6/2007	6.06	4	2007	4/6/2007	6.04	4	2007
4	2007	4/4/2007	4.8422	4	2007	4/9/2007	6.06	4	2007	4/9/2007	6.03	4	2007
4	2007	4/5/2007	4.8745	4	2007	4/10/2007	6.04	4	2007	4/10/2007	6.02	4	2007
4	2007	4/6/2007	4.9203	4	2007	4/11/2007	6.04	4	2007	4/11/2007	6.02	4	2007
4	2007	4/9/2007	4.9183	4	2007	4/12/2007	6.04	4	2007	4/12/2007	6.02	4	2007
4	2007	4/10/2007	4.904	4	2007	4/13/2007	6.05	4	2007	4/13/2007	6.03	4	2007
4	2007	4/11/2007	4.908	4	2007	4/16/2007	6.01	4	2007	4/16/2007	6	4	2007
4	2007	4/12/2007	4.907	4	2007	4/17/2007	5.96	4	2007	4/17/2007	5.95	4	2007
4	2007	4/13/2007	4.9296	4	2007	4/18/2007	5.93	4	2007	4/18/2007	5.92	4	2007
4	2007	4/16/2007	4.8897	4	2007	4/19/2007	5.95	4	2007	4/19/2007	5.94	4	2007
4	2007	4/17/2007	4.8432	4	2007	4/20/2007	5.96	4	2007	4/20/2007	5.94	4	2007
4	2007	4/18/2007	4.8151	4	2007	4/23/2007	5.94	4	2007	4/23/2007	5.93	4	2007
4	2007	4/19/2007	4.8331	4	2007	4/24/2007	5.91	4	2007	4/24/2007	5.9	4	2007
4	2007	4/20/2007	4.8452	4	2007	4/25/2007	5.94	4	2007	4/25/2007	5.92	4	2007
4	2007	4/23/2007	4.8221	4	2007	4/26/2007	5.98	4	2007	4/26/2007	5.96	4	2007
4	2007	4/24/2007	4.8061	4	2007	4/27/2007	5.99	4	2007	4/27/2007	5.97	4	2007

4	2007	4/25/2007	4.8331	4	2007	4/30/2007	5.92	4	2007	4/30/2007	5.9	4	2007
4	2007	4/26/2007	4.8806	5	2007	5/1/2007	5.92	5	2007	5/1/2007	5.9	5	2007
4	2007	4/27/2007	4.8806	5	2007	5/2/2007	5.92	5	2007	5/2/2007	5.9	5	2007
4	2007	4/30/2007	4.8131	5	2007	5/3/2007	5.94	5	2007	5/3/2007	5.92	5	2007
5	2007	5/1/2007	4.8151	5	2007	5/4/2007	5.9	5	2007	5/4/2007	5.88	5	2007
5	2007	5/2/2007	4.8151	5	2007	5/7/2007	5.9	5	2007	5/7/2007	5.87	5	2007
5	2007	5/3/2007	4.8382	5	2007	5/8/2007	5.91	5	2007	5/8/2007	5.88	5	2007
5	2007	5/4/2007	4.8051	5	2007	5/9/2007	5.94	5	2007	5/9/2007	5.92	5	2007
5	2007	5/7/2007	4.7822	5	2007	5/10/2007	5.93	5	2007	5/10/2007	5.91	5	2007
5	2007	5/8/2007	4.8021	5	2007	5/11/2007	5.95	5	2007	5/11/2007	5.93	5	2007
5	2007	5/9/2007	4.8362	5	2007	5/14/2007	5.96	5	2007	5/14/2007	5.94	5	2007
5	2007	5/10/2007	4.8221	5	2007	5/15/2007	5.99	5	2007	5/15/2007	5.97	5	2007
5	2007	5/11/2007	4.8493	5	2007	5/16/2007	5.98	5	2007	5/16/2007	5.96	5	2007
5	2007	5/14/2007	4.8675	5	2007	5/17/2007	6.01	5	2007	5/17/2007	6	5	2007
5	2007	5/15/2007	4.8746	5	2007	5/18/2007	6.05	5	2007	5/18/2007	6.04	5	2007
5	2007	5/16/2007	4.8787	5	2007	5/21/2007	6.04	5	2007	5/21/2007	6.03	5	2007
5	2007	5/17/2007	4.9133	5	2007	5/22/2007	6.08	5	2007	5/22/2007	6.07	5	2007
5	2007	5/18/2007	4.9576	5	2007	5/23/2007	6.11	5	2007	5/23/2007	6.1	5	2007
5	2007	5/21/2007	4.937	5	2007	5/24/2007	6.1	5	2007	5/24/2007	6.09	5	2007
5	2007	5/22/2007	4.9804	5	2007	5/25/2007	6.1	5	2007	5/25/2007	6.09	5	2007
5	2007	5/23/2007	5.0034	5	2007	5/29/2007	6.11	5	2007	5/29/2007	6.1	5	2007
5	2007	5/24/2007	4.9898	5	2007	5/30/2007	6.1	5	2007	5/30/2007	6.09	5	2007
5	2007	5/25/2007	5.0024	5	2007	5/31/2007	6.11	5	2007	5/31/2007	6.1	5	2007
5	2007	5/28/2007	5.0024	6	2007	6/1/2007	6.16	6	2007	6/1/2007	6.15	6	2007
5	2007	5/29/2007	5.0171	6	2007	6/4/2007	6.12	6	2007	6/4/2007	6.11	6	2007
5	2007	5/30/2007	5.0014	6	2007	6/5/2007	6.17	6	2007	6/5/2007	6.15	6	2007
5	2007	5/31/2007	5.0098	6	2007	6/6/2007	6.18	6	2007	6/6/2007	6.17	6	2007
6	2007	6/1/2007	5.0572	6	2007	6/7/2007	6.31	6	2007	6/7/2007	6.3	6	2007
6	2007	6/4/2007	5.0224	6	2007	6/8/2007	6.34	6	2007	6/8/2007	6.33	6	2007
6	2007	6/5/2007	5.087	6	2007	6/11/2007	6.36	6	2007	6/11/2007	6.34	6	2007
6	2007	6/6/2007	5.0806	6	2007	6/12/2007	6.47	6	2007	6/12/2007	6.45	6	2007
6	2007	6/7/2007	5.23	6	2007	6/13/2007	6.39	6	2007	6/13/2007	6.37	6	2007
6	2007	6/8/2007	5.207	6	2007	6/14/2007	6.41	6	2007	6/14/2007	6.39	6	2007
6	2007	6/11/2007	5.2555	6	2007	6/15/2007	6.38	6	2007	6/15/2007	6.36	6	2007
6	2007	6/12/2007	5.4019	6	2007	6/18/2007	6.37	6	2007	6/18/2007	6.35	6	2007
6	2007	6/13/2007	5.2789	6	2007	6/19/2007	6.32	6	2007	6/19/2007	6.3	6	2007
6	2007	6/14/2007	5.3012	6	2007	6/20/2007	6.35	6	2007	6/20/2007	6.34	6	2007
6	2007	6/15/2007	5.259	6	2007	6/21/2007	6.4	6	2007	6/21/2007	6.39	6	2007
6	2007	6/18/2007	5.2523	6	2007	6/22/2007	6.38	6	2007	6/22/2007	6.36	6	2007
6	2007	6/19/2007	5.1952	6	2007	6/25/2007	6.32	6	2007	6/25/2007	6.3	6	2007
6	2007	6/20/2007	5.2413	6	2007	6/26/2007	6.34	6	2007	6/26/2007	6.33	6	2007
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2	2008	2/11/2008	4.3986	2	2008	2/28/2008	6.27	2	2008	2/28/2008	6.22	2	2008
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2	2008	2/13/2008	4.537	3	2008	3/3/2008	6.15	3	2008	3/3/2008	6.1	3	2008
2	2008	2/14/2008	4.6368	3	2008	3/4/2008	6.21	3	2008	3/4/2008	6.16	3	2008
2	2008	2/15/2008	4.5762	3	2008	3/5/2008	6.34	3	2008	3/5/2008	6.29	3	2008
2	2008	2/18/2008	4.5762	3	2008	3/6/2008	6.35	3	2008	3/6/2008	6.3	3	2008
2	2008	2/19/2008	4.6649	3	2008	3/7/2008	6.32	3	2008	3/7/2008	6.28	3	2008
2	2008	2/20/2008	4.6079	3	2008	3/10/2008	6.25	3	2008	3/10/2008	6.22	3	2008
2	2008	2/21/2008	4.5438	3	2008	3/11/2008	6.35	3	2008	3/11/2008	6.32	3	2008
2	2008	2/22/2008	4.5733	3	2008	3/12/2008	6.22	3	2008	3/12/2008	6.19	3	2008
2	2008	2/25/2008	4.6549	3	2008	3/13/2008	6.28	3	2008	3/13/2008	6.24	3	2008
2	2008	2/26/2008	4.6559	3	2008	3/14/2008	6.2	3	2008	3/14/2008	6.17	3	2008
2	2008	2/27/2008	4.6499	3	2008	3/17/2008	6.17	3	2008	3/17/2008	6.15	3	2008
2	2008	2/28/2008	4.5213	3	2008	3/18/2008	6.21	3	2008	3/18/2008	6.18	3	2008
2	2008	2/29/2008	4.4023	3	2008	3/19/2008	6.14	3	2008	3/19/2008	6.11	3	2008
3	2008	3/3/2008	4.4327	3	2008	3/20/2008	6.08	3	2008	3/20/2008	6.07	3	2008
3	2008	3/4/2008	4.5068	3	2008	3/24/2008	6.21	3	2008	3/24/2008	6.2	3	2008
3	2008	3/5/2008	4.598	3	2008	3/25/2008	6.22	3	2008	3/25/2008	6.21	3	2008
3	2008	3/6/2008	4.5605	3	2008	3/26/2008	6.24	3	2008	3/26/2008	6.25	3	2008
3	2008	3/7/2008	4.5399	3	2008	3/27/2008	6.29	3	2008	3/27/2008	6.29	3	2008
3	2008	3/10/2008	4.4633	3	2008	3/28/2008	6.25	3	2008	3/28/2008	6.25	3	2008
3	2008	3/11/2008	4.5077	3	2008	3/31/2008	6.21	3	2008	3/31/2008	6.2	3	2008
3	2008	3/12/2008	4.4098	4	2008	4/1/2008	6.31	4	2008	4/1/2008	6.29	4	2008
3	2008	3/13/2008	4.447	4	2008	4/2/2008	6.31	4	2008	4/2/2008	6.31	4	2008
3	2008	3/14/2008	4.3635	4	2008	4/3/2008	6.3	4	2008	4/3/2008	6.31	4	2008
3	2008	3/17/2008	4.2854	4	2008	4/4/2008	6.22	4	2008	4/4/2008	6.23	4	2008
3	2008	3/18/2008	4.3485	4	2008	4/7/2008	6.26	4	2008	4/7/2008	6.28	4	2008
3	2008	3/19/2008	4.2104	4	2008	4/8/2008	6.28	4	2008	4/8/2008	6.29	4	2008
3	2008	3/20/2008	4.1599	4	2008	4/9/2008	6.2	4	2008	4/9/2008	6.22	4	2008
3	2008	3/21/2008	4.1599	4	2008	4/10/2008	6.22	4	2008	4/10/2008	6.24	4	2008
3	2008	3/24/2008	4.3644	4	2008	4/11/2008	6.18	4	2008	4/11/2008	6.2	4	2008
3	2008	3/25/2008	4.3028	4	2008	4/14/2008	6.23	4	2008	4/14/2008	6.24	4	2008
3	2008	3/26/2008	4.3065	4	2008	4/15/2008	6.28	4	2008	4/15/2008	6.3	4	2008
3	2008	3/27/2008	4.3898	4	2008	4/16/2008	6.41	4	2008	4/16/2008	6.41	4	2008
3	2008	3/28/2008	4.3177	4	2008	4/17/2008	6.4	4	2008	4/17/2008	6.4	4	2008
3	2008	3/31/2008	4.2917	4	2008	4/18/2008	6.34	4	2008	4/18/2008	6.32	4	2008
4	2008	4/1/2008	4.3993	4	2008	4/21/2008	6.29	4	2008	4/21/2008	6.27	4	2008
4	2008	4/2/2008	4.405	4	2008	4/22/2008	6.27	4	2008	4/22/2008	6.27	4	2008
4	2008	4/3/2008	4.3785	4	2008	4/23/2008	6.28	4	2008	4/23/2008	6.28	4	2008
4	2008	4/4/2008	4.3055	4	2008	4/24/2008	6.34	4	2008	4/24/2008	6.34	4	2008
4	2008	4/7/2008	4.3447	4	2008	4/25/2008	6.38	4	2008	4/25/2008	6.38	4	2008
4	2008	4/8/2008	4.3794	4	2008	4/28/2008	6.33	4	2008	4/28/2008	6.3	4	2008
4	2008	4/9/2008	4.3204	4	2008	4/29/2008	6.31	4	2008	4/29/2008	6.29	4	2008
4	2008	4/10/2008	4.3484	4	2008	4/30/2008	6.23	4	2008	4/30/2008	6.22	4	2008

4	2008	4/11/2008	4.299	5	2008	5/1/2008	6.2	5	2008	5/1/2008	6.19	5	2008
4	2008	4/14/2008	4.3493	5	2008	5/2/2008	6.25	5	2008	5/2/2008	6.24	5	2008
4	2008	4/15/2008	4.4412	5	2008	5/5/2008	6.27	5	2008	5/5/2008	6.26	5	2008
4	2008	4/16/2008	4.4932	5	2008	5/6/2008	6.33	5	2008	5/6/2008	6.32	5	2008
4	2008	4/17/2008	4.5263	5	2008	5/7/2008	6.31	5	2008	5/7/2008	6.3	5	2008
4	2008	4/18/2008	4.4961	5	2008	5/8/2008	6.26	5	2008	5/8/2008	6.24	5	2008
4	2008	4/21/2008	4.4884	5	2008	5/9/2008	6.22	5	2008	5/9/2008	6.2	5	2008
4	2008	4/22/2008	4.4441	5	2008	5/12/2008	6.22	5	2008	5/12/2008	6.2	5	2008
4	2008	4/23/2008	4.4913	5	2008	5/13/2008	6.33	5	2008	5/13/2008	6.3	5	2008
4	2008	4/24/2008	4.5459	5	2008	5/14/2008	6.36	5	2008	5/14/2008	6.32	5	2008
4	2008	4/25/2008	4.5914	5	2008	5/15/2008	6.29	5	2008	5/15/2008	6.26	5	2008
4	2008	4/28/2008	4.5597	5	2008	5/16/2008	6.29	5	2008	5/16/2008	6.27	5	2008
4	2008	4/29/2008	4.5509	5	2008	5/19/2008	6.28	5	2008	5/19/2008	6.25	5	2008
4	2008	4/30/2008	4.4672	5	2008	5/20/2008	6.24	5	2008	5/20/2008	6.22	5	2008
5	2008	5/1/2008	4.4991	5	2008	5/21/2008	6.27	5	2008	5/21/2008	6.24	5	2008
5	2008	5/2/2008	4.5775	5	2008	5/22/2008	6.34	5	2008	5/22/2008	6.29	5	2008
5	2008	5/5/2008	4.6014	5	2008	5/23/2008	6.27	5	2008	5/23/2008	6.22	5	2008
5	2008	5/6/2008	4.6625	5	2008	5/27/2008	6.37	5	2008	5/27/2008	6.32	5	2008
5	2008	5/7/2008	4.6054	5	2008	5/28/2008	6.42	5	2008	5/28/2008	6.37	5	2008
5	2008	5/8/2008	4.5421	5	2008	5/29/2008	6.49	5	2008	5/29/2008	6.42	5	2008
5	2008	5/9/2008	4.5216	5	2008	5/30/2008	6.42	5	2008	5/30/2008	6.36	5	2008
5	2008	5/12/2008	4.5343	6	2008	6/2/2008	6.39	6	2008	6/2/2008	6.34	6	2008
5	2008	5/13/2008	4.6384	6	2008	6/3/2008	6.32	6	2008	6/3/2008	6.27	6	2008
5	2008	5/14/2008	4.6134	6	2008	6/4/2008	6.39	6	2008	6/4/2008	6.34	6	2008
5	2008	5/15/2008	4.551	6	2008	6/5/2008	6.44	6	2008	6/5/2008	6.38	6	2008
5	2008	5/16/2008	4.5737	6	2008	6/6/2008	6.35	6	2008	6/6/2008	6.29	6	2008
5	2008	5/19/2008	4.5717	6	2008	6/9/2008	6.33	6	2008	6/9/2008	6.26	6	2008
5	2008	5/20/2008	4.5294	6	2008	6/10/2008	6.42	6	2008	6/10/2008	6.35	6	2008
5	2008	5/21/2008	4.5392	6	2008	6/11/2008	6.43	6	2008	6/11/2008	6.37	6	2008
5	2008	5/22/2008	4.6205	6	2008	6/12/2008	6.49	6	2008	6/12/2008	6.44	6	2008
5	2008	5/23/2008	4.5678	6	2008	6/13/2008	6.52	6	2008	6/13/2008	6.48	6	2008
5	2008	5/26/2008	4.5728	6	2008	6/16/2008	6.51	6	2008	6/16/2008	6.47	6	2008
5	2008	5/27/2008	4.6406	6	2008	6/17/2008	6.52	6	2008	6/17/2008	6.48	6	2008
5	2008	5/28/2008	4.6881	6	2008	6/18/2008	6.46	6	2008	6/18/2008	6.42	6	2008
5	2008	5/29/2008	4.7475	6	2008	6/19/2008	6.49	6	2008	6/19/2008	6.44	6	2008
5	2008	5/30/2008	4.7147	6	2008	6/20/2008	6.45	6	2008	6/20/2008	6.4	6	2008
6	2008	6/2/2008	4.67	6	2008	6/23/2008	6.46	6	2008	6/23/2008	6.41	6	2008
6	2008	6/3/2008	4.6206	6	2008	6/24/2008	6.42	6	2008	6/24/2008	6.38	6	2008
6	2008	6/4/2008	4.6984	6	2008	6/25/2008	6.42	6	2008	6/25/2008	6.39	6	2008
6	2008	6/5/2008	4.7363	6	2008	6/26/2008	6.42	6	2008	6/26/2008	6.38	6	2008
6	2008	6/6/2008	4.6237	6	2008	6/27/2008	6.35	6	2008	6/27/2008	6.31	6	2008
6	2008	6/9/2008	4.6297	6	2008	6/30/2008	6.36	6	2008	6/30/2008	6.32	6	2008

6	2008	6/10/2008	4.6985	7	2008	7/1/2008	6.38	7	2008	7/1/2008	6.34	7	2008
6	2008	6/11/2008	4.6945	7	2008	7/2/2008	6.33	7	2008	7/2/2008	6.3	7	2008
6	2008	6/12/2008	4.7571	7	2008	7/3/2008	6.37	7	2008	7/3/2008	6.33	7	2008
6	2008	6/13/2008	4.7893	7	2008	7/7/2008	6.34	7	2008	7/7/2008	6.3	7	2008
6	2008	6/16/2008	4.7914	7	2008	7/8/2008	6.3	7	2008	7/8/2008	6.26	7	2008
6	2008	6/17/2008	4.7675	7	2008	7/9/2008	6.28	7	2008	7/9/2008	6.23	7	2008
6	2008	6/18/2008	4.713	7	2008	7/10/2008	6.28	7	2008	7/10/2008	6.22	7	2008
6	2008	6/19/2008	4.7582	7	2008	7/11/2008	6.38	7	2008	7/11/2008	6.33	7	2008
6	2008	6/20/2008	4.7243	7	2008	7/14/2008	6.33	7	2008	7/14/2008	6.29	7	2008
6	2008	6/23/2008	4.7008	7	2008	7/15/2008	6.36	7	2008	7/15/2008	6.32	7	2008
6	2008	6/24/2008	4.636	7	2008	7/16/2008	6.48	7	2008	7/16/2008	6.44	7	2008
6	2008	6/25/2008	4.643	7	2008	7/17/2008	6.54	7	2008	7/17/2008	6.49	7	2008
6	2008	6/26/2008	4.601	7	2008	7/18/2008	6.56	7	2008	7/18/2008	6.51	7	2008
6	2008	6/27/2008	4.521	7	2008	7/21/2008	6.54	7	2008	7/21/2008	6.49	7	2008
6	2008	6/30/2008	4.5239	7	2008	7/22/2008	6.56	7	2008	7/22/2008	6.51	7	2008
7	2008	7/1/2008	4.5485	7	2008	7/23/2008	6.59	7	2008	7/23/2008	6.54	7	2008
7	2008	7/2/2008	4.5025	7	2008	7/24/2008	6.5	7	2008	7/24/2008	6.45	7	2008
7	2008	7/3/2008	4.5348	7	2008	7/25/2008	6.58	7	2008	7/25/2008	6.54	7	2008
7	2008	7/4/2008	4.5328	7	2008	7/28/2008	6.5	7	2008	7/28/2008	6.46	7	2008
7	2008	7/7/2008	4.484	7	2008	7/29/2008	6.51	7	2008	7/29/2008	6.46	7	2008
7	2008	7/8/2008	4.4502	7	2008	7/30/2008	6.53	7	2008	7/30/2008	6.48	7	2008
7	2008	7/9/2008	4.4176	7	2008	7/31/2008	6.49	7	2008	7/31/2008	6.44	7	2008
7	2008	7/10/2008	4.4138	8	2008	8/1/2008	6.47	8	2008	8/1/2008	6.42	8	2008
7	2008	7/11/2008	4.5398	8	2008	8/4/2008	6.48	8	2008	8/4/2008	6.43	8	2008
7	2008	7/14/2008	4.4464	8	2008	8/5/2008	6.52	8	2008	8/5/2008	6.47	8	2008
7	2008	7/15/2008	4.458	8	2008	8/6/2008	6.58	8	2008	8/6/2008	6.53	8	2008
7	2008	7/16/2008	4.5853	8	2008	8/7/2008	6.47	8	2008	8/7/2008	6.42	8	2008
7	2008	7/17/2008	4.6073	8	2008	8/8/2008	6.45	8	2008	8/8/2008	6.41	8	2008
7	2008	7/18/2008	4.6475	8	2008	8/11/2008	6.51	8	2008	8/11/2008	6.46	8	2008
7	2008	7/21/2008	4.6214	8	2008	8/12/2008	6.46	8	2008	8/12/2008	6.4	8	2008
7	2008	7/22/2008	4.6587	8	2008	8/13/2008	6.47	8	2008	8/13/2008	6.41	8	2008
7	2008	7/23/2008	4.6739	8	2008	8/14/2008	6.43	8	2008	8/14/2008	6.37	8	2008
7	2008	7/24/2008	4.6014	8	2008	8/15/2008	6.39	8	2008	8/15/2008	6.33	8	2008
7	2008	7/25/2008	4.6852	8	2008	8/18/2008	6.35	8	2008	8/18/2008	6.3	8	2008
7	2008	7/28/2008	4.6015	8	2008	8/19/2008	6.38	8	2008	8/19/2008	6.33	8	2008
7	2008	7/29/2008	4.6235	8	2008	8/20/2008	6.36	8	2008	8/20/2008	6.31	8	2008
7	2008	7/30/2008	4.6447	8	2008	8/21/2008	6.39	8	2008	8/21/2008	6.35	8	2008
7	2008	7/31/2008	4.5727	8	2008	8/22/2008	6.4	8	2008	8/22/2008	6.36	8	2008
8	2008	8/1/2008	4.5608	8	2008	8/25/2008	6.34	8	2008	8/25/2008	6.3	8	2008
8	2008	8/4/2008	4.5896	8	2008	8/26/2008	6.35	8	2008	8/26/2008	6.3	8	2008
8	2008	8/5/2008	4.6408	8	2008	8/27/2008	6.32	8	2008	8/27/2008	6.28	8	2008
8	2008	8/6/2008	4.6925	8	2008	8/28/2008	6.34	8	2008	8/28/2008	6.29	8	2008

8	2008	8/7/2008	4.555	8	2008	8/29/2008	6.38	8	2008	8/29/2008	6.32	8	2008
8	2008	8/8/2008	4.5333	9	2008	9/2/2008	6.33	9	2008	9/2/2008	6.26	9	2008
8	2008	8/11/2008	4.6024	9	2008	9/3/2008	6.29	9	2008	9/3/2008	6.23	9	2008
8	2008	8/12/2008	4.5333	9	2008	9/4/2008	6.26	9	2008	9/4/2008	6.21	9	2008
8	2008	8/13/2008	4.5594	9	2008	9/5/2008	6.27	9	2008	9/5/2008	6.21	9	2008
8	2008	8/14/2008	4.5169	9	2008	9/8/2008	6.27	9	2008	9/8/2008	6.2	9	2008
8	2008	8/15/2008	4.4634	9	2008	9/9/2008	6.2	9	2008	9/9/2008	6.14	9	2008
8	2008	8/18/2008	4.434	9	2008	9/10/2008	6.26	9	2008	9/10/2008	6.19	9	2008
8	2008	8/19/2008	4.4615	9	2008	9/11/2008	6.27	9	2008	9/11/2008	6.22	9	2008
8	2008	8/20/2008	4.4453	9	2008	9/12/2008	6.4	9	2008	9/12/2008	6.34	9	2008
8	2008	8/21/2008	4.4624	9	2008	9/15/2008	6.34	9	2008	9/15/2008	6.31	9	2008
8	2008	8/22/2008	4.4662	9	2008	9/16/2008	6.35	9	2008	9/16/2008	6.34	9	2008
8	2008	8/25/2008	4.3936	9	2008	9/17/2008	6.42	9	2008	9/17/2008	6.43	9	2008
8	2008	8/26/2008	4.3871	9	2008	9/18/2008	6.5	9	2008	9/18/2008	6.49	9	2008
8	2008	8/27/2008	4.3815	9	2008	9/19/2008	6.73	9	2008	9/19/2008	6.78	9	2008
8	2008	8/28/2008	4.3759	9	2008	9/22/2008	6.76	9	2008	9/22/2008	6.79	9	2008
8	2008	8/29/2008	4.4227	9	2008	9/23/2008	6.78	9	2008	9/23/2008	6.81	9	2008
9	2008	9/1/2008	4.4227	9	2008	9/24/2008	6.74	9	2008	9/24/2008	6.76	9	2008
9	2008	9/2/2008	4.3554	9	2008	9/25/2008	6.87	9	2008	9/25/2008	6.93	9	2008
9	2008	9/3/2008	4.3185	9	2008	9/26/2008	6.87	9	2008	9/26/2008	6.92	9	2008
9	2008	9/4/2008	4.2592	9	2008	9/29/2008	6.74	9	2008	9/29/2008	6.82	9	2008
9	2008	9/5/2008	4.3019	9	2008	9/30/2008	6.94	9	2008	9/30/2008	6.98	9	2008
9	2008	9/8/2008	4.2664	10	2008	10/1/2008	6.92	10	2008	10/1/2008	6.93	10	2008
9	2008	9/9/2008	4.1703	10	2008	10/2/2008	6.97	10	2008	10/2/2008	6.97	10	2008
9	2008	9/10/2008	4.2257	10	2008	10/3/2008	6.95	10	2008	10/3/2008	6.94	10	2008
9	2008	9/11/2008	4.2212	10	2008	10/6/2008	6.87	10	2008	10/6/2008	6.86	10	2008
9	2008	9/12/2008	4.3147	10	2008	10/7/2008	6.97	10	2008	10/7/2008	6.95	10	2008
9	2008	9/15/2008	4.0227	10	2008	10/8/2008	7.11	10	2008	10/8/2008	7.1	10	2008
9	2008	9/16/2008	4.091	10	2008	10/9/2008	7.22	10	2008	10/9/2008	7.2	10	2008
9	2008	9/17/2008	4.0736	10	2008	10/10/2008	7.5	10	2008	10/10/2008	7.44	10	2008
9	2008	9/18/2008	4.1889	10	2008	10/14/2008	7.64	10	2008	10/14/2008	7.56	10	2008
9	2008	9/19/2008	4.3823	10	2008	10/15/2008	7.66	10	2008	10/15/2008	7.63	10	2008
9	2008	9/22/2008	4.4208	10	2008	10/16/2008	7.75	10	2008	10/16/2008	7.74	10	2008
9	2008	9/23/2008	4.3804	10	2008	10/17/2008	7.98	10	2008	10/17/2008	8.02	10	2008
9	2008	9/24/2008	4.4123	10	2008	10/20/2008	7.96	10	2008	10/20/2008	8	10	2008
9	2008	9/25/2008	4.4095	10	2008	10/21/2008	7.91	10	2008	10/21/2008	7.93	10	2008
9	2008	9/26/2008	4.3702	10	2008	10/22/2008	7.77	10	2008	10/22/2008	7.8	10	2008
9	2008	9/29/2008	4.1127	10	2008	10/23/2008	7.63	10	2008	10/23/2008	7.69	10	2008
9	2008	9/30/2008	4.311	10	2008	10/24/2008	7.78	10	2008	10/24/2008	7.82	10	2008
10	2008	10/1/2008	4.2147	10	2008	10/27/2008	7.85	10	2008	10/27/2008	7.87	10	2008
10	2008	10/2/2008	4.1514	10	2008	10/28/2008	7.94	10	2008	10/28/2008	7.94	10	2008
10	2008	10/3/2008	4.0872	10	2008	10/29/2008	7.98	10	2008	10/29/2008	8	10	2008

10	2008	10/6/2008	3.972	10	2008	10/30/2008	7.98	10	2008	10/30/2008	8	10	2008
10	2008	10/7/2008	4.0301	10	2008	10/31/2008	8.01	10	2008	10/31/2008	8.01	10	2008
10	2008	10/8/2008	4.0482	11	2008	11/3/2008	7.95	11	2008	11/3/2008	7.94	11	2008
10	2008	10/9/2008	4.102	11	2008	11/4/2008	7.85	11	2008	11/4/2008	7.85	11	2008
10	2008	10/10/2008	4.1363	11	2008	11/5/2008	7.77	11	2008	11/5/2008	7.78	11	2008
10	2008	10/13/2008	4.1362	11	2008	11/6/2008	7.77	11	2008	11/6/2008	7.75	11	2008
10	2008	10/14/2008	4.2761	11	2008	11/7/2008	7.82	11	2008	11/7/2008	7.78	11	2008
10	2008	10/15/2008	4.1913	11	2008	11/10/2008	7.76	11	2008	11/10/2008	7.73	11	2008
10	2008	10/16/2008	4.2561	11	2008	11/12/2008	7.71	11	2008	11/12/2008	7.68	11	2008
10	2008	10/17/2008	4.3229	11	2008	11/13/2008	7.9	11	2008	11/13/2008	7.84	11	2008
10	2008	10/20/2008	4.2552	11	2008	11/14/2008	7.78	11	2008	11/14/2008	7.71	11	2008
10	2008	10/21/2008	4.2163	11	2008	11/17/2008	7.76	11	2008	11/17/2008	7.7	11	2008
10	2008	10/22/2008	4.0548	11	2008	11/18/2008	7.68	11	2008	11/18/2008	7.65	11	2008
10	2008	10/23/2008	4.0496	11	2008	11/19/2008	7.54	11	2008	11/19/2008	7.48	11	2008
10	2008	10/24/2008	4.0687	11	2008	11/20/2008	7.38	11	2008	11/20/2008	7.34	11	2008
10	2008	10/27/2008	4.0453	11	2008	11/21/2008	7.42	11	2008	11/21/2008	7.36	11	2008
10	2008	10/28/2008	4.1912	11	2008	11/24/2008	7.54	11	2008	11/24/2008	7.47	11	2008
10	2008	10/29/2008	4.237	11	2008	11/25/2008	7.41	11	2008	11/25/2008	7.33	11	2008
10	2008	10/30/2008	4.3302	11	2008	11/26/2008	7.34	11	2008	11/26/2008	7.25	11	2008
10	2008	10/31/2008	4.3664	11	2008	11/28/2008	7.29	11	2008	11/28/2008	7.18	11	2008
11	2008	11/3/2008	4.3219	12	2008	12/1/2008	7.05	12	2008	12/1/2008	6.93	12	2008
11	2008	11/4/2008	4.192	12	2008	12/2/2008	7.03	12	2008	12/2/2008	6.91	12	2008
11	2008	11/5/2008	4.175	12	2008	12/3/2008	7.02	12	2008	12/3/2008	6.88	12	2008
11	2008	11/6/2008	4.1983	12	2008	12/4/2008	6.96	12	2008	12/4/2008	6.78	12	2008
11	2008	11/7/2008	4.2733	12	2008	12/5/2008	7	12	2008	12/5/2008	6.81	12	2008
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11	2008	11/25/2008	3.6194	12	2008	12/23/2008	6.44	12	2008	12/23/2008	6.23	12	2008
11	2008	11/26/2008	3.5226	12	2008	12/24/2008	6.41	12	2008	12/24/2008	6.22	12	2008
11	2008	11/27/2008	3.5225	12	2008	12/26/2008	6.36	12	2008	12/26/2008	6.17	12	2008
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2	2009	2/5/2009	3.6477	3	2009	3/11/2009	6.82	3	2009	3/11/2009	6.4	3	2009
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5	2009	5/28/2009	4.4873	7	2009	7/6/2009	6.24	7	2009	7/6/2009	6	7	2009
5	2009	5/29/2009	4.3361	7	2009	7/7/2009	6.19	7	2009	7/7/2009	5.96	7	2009
6	2009	6/1/2009	4.5337	7	2009	7/8/2009	6.05	7	2009	7/8/2009	5.82	7	2009
6	2009	6/2/2009	4.4824	7	2009	7/9/2009	6.2	7	2009	7/9/2009	5.98	7	2009
6	2009	6/3/2009	4.4453	7	2009	7/10/2009	6.09	7	2009	7/10/2009	5.88	7	2009
6	2009	6/4/2009	4.5785	7	2009	7/13/2009	6.1	7	2009	7/13/2009	5.87	7	2009
6	2009	6/5/2009	4.633	7	2009	7/14/2009	6.21	7	2009	7/14/2009	5.98	7	2009
6	2009	6/8/2009	4.6138	7	2009	7/15/2009	6.31	7	2009	7/15/2009	6.11	7	2009
6	2009	6/9/2009	4.6524	7	2009	7/16/2009	6.25	7	2009	7/16/2009	6.07	7	2009
6	2009	6/10/2009	4.762	7	2009	7/17/2009	6.29	7	2009	7/17/2009	6.08	7	2009
6	2009	6/11/2009	4.6965	7	2009	7/20/2009	6.21	7	2009	7/20/2009	6	7	2009
6	2009	6/12/2009	4.6443	7	2009	7/21/2009	6.1	7	2009	7/21/2009	5.9	7	2009
6	2009	6/15/2009	4.5606	7	2009	7/22/2009	6.18	7	2009	7/22/2009	5.97	7	2009
6	2009	6/16/2009	4.4727	7	2009	7/23/2009	6.28	7	2009	7/23/2009	6.09	7	2009
6	2009	6/17/2009	4.51	7	2009	7/24/2009	6.21	7	2009	7/24/2009	6.02	7	2009
6	2009	6/18/2009	4.6038	7	2009	7/27/2009	6.27	7	2009	7/27/2009	6.09	7	2009
6	2009	6/19/2009	4.5041	7	2009	7/28/2009	6.18	7	2009	7/28/2009	6.01	7	2009
6	2009	6/22/2009	4.4376	7	2009	7/29/2009	6.07	7	2009	7/29/2009	5.93	7	2009
6	2009	6/23/2009	4.3569	7	2009	7/30/2009	5.98	7	2009	7/30/2009	5.83	7	2009
6	2009	6/24/2009	4.427	7	2009	7/31/2009	5.82	7	2009	7/31/2009	5.68	7	2009
6	2009	6/25/2009	4.3341	8	2009	8/3/2009	5.91	8	2009	8/3/2009	5.77	8	2009
6	2009	6/26/2009	4.336	8	2009	8/4/2009	5.92	8	2009	8/4/2009	5.81	8	2009
6	2009	6/29/2009	4.287	8	2009	8/5/2009	5.99	8	2009	8/5/2009	5.9	8	2009
6	2009	6/30/2009	4.3294	8	2009	8/6/2009	5.93	8	2009	8/6/2009	5.84	8	2009
7	2009	7/1/2009	4.3285	8	2009	8/7/2009	6.01	8	2009	8/7/2009	5.89	8	2009
7	2009	7/2/2009	4.3181	8	2009	8/10/2009	5.93	8	2009	8/10/2009	5.81	8	2009
7	2009	7/3/2009	4.3209	8	2009	8/11/2009	5.87	8	2009	8/11/2009	5.75	8	2009
7	2009	7/6/2009	4.3579	8	2009	8/12/2009	5.97	8	2009	8/12/2009	5.84	8	2009
7	2009	7/7/2009	4.3086	8	2009	8/13/2009	5.85	8	2009	8/13/2009	5.74	8	2009
7	2009	7/8/2009	4.1935	8	2009	8/14/2009	5.85	8	2009	8/14/2009	5.72	8	2009
7	2009	7/9/2009	4.3002	8	2009	8/17/2009	5.82	8	2009	8/17/2009	5.68	8	2009
7	2009	7/10/2009	4.1989	8	2009	8/18/2009	5.84	8	2009	8/18/2009	5.71	8	2009
7	2009	7/13/2009	4.2321	8	2009	8/19/2009	5.79	8	2009	8/19/2009	5.66	8	2009
7	2009	7/14/2009	4.3741	8	2009	8/20/2009	5.75	8	2009	8/20/2009	5.61	8	2009
7	2009	7/15/2009	4.4886	8	2009	8/21/2009	5.86	8	2009	8/21/2009	5.73	8	2009
7	2009	7/16/2009	4.4475	8	2009	8/24/2009	5.78	8	2009	8/24/2009	5.65	8	2009
7	2009	7/17/2009	4.535	8	2009	8/25/2009	5.72	8	2009	8/25/2009	5.57	8	2009
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7	2009	7/22/2009	4.4465	8	2009	8/28/2009	5.67	8	2009	8/28/2009	5.56	8	2009
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7	2009	7/24/2009	4.5391	9	2009	9/1/2009	5.66	9	2009	9/1/2009	5.55	9	2009

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7	2009	7/28/2009	4.5491	9	2009	9/3/2009	5.6	9	2009	9/3/2009	5.5	9	2009
7	2009	7/29/2009	4.5074	9	2009	9/4/2009	5.72	9	2009	9/4/2009	5.62	9	2009
7	2009	7/30/2009	4.4107	9	2009	9/8/2009	5.75	9	2009	9/8/2009	5.66	9	2009
7	2009	7/31/2009	4.2983	9	2009	9/9/2009	5.78	9	2009	9/9/2009	5.68	9	2009
8	2009	8/3/2009	4.404	9	2009	9/10/2009	5.61	9	2009	9/10/2009	5.52	9	2009
8	2009	8/4/2009	4.4632	9	2009	9/11/2009	5.6	9	2009	9/11/2009	5.52	9	2009
8	2009	8/5/2009	4.5492	9	2009	9/14/2009	5.65	9	2009	9/14/2009	5.57	9	2009
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8	2009	8/7/2009	4.6045	9	2009	9/16/2009	5.68	9	2009	9/16/2009	5.61	9	2009
8	2009	8/10/2009	4.5313	9	2009	9/17/2009	5.59	9	2009	9/17/2009	5.52	9	2009
8	2009	8/11/2009	4.436	9	2009	9/18/2009	5.65	9	2009	9/18/2009	5.58	9	2009
8	2009	8/12/2009	4.5373	9	2009	9/21/2009	5.65	9	2009	9/21/2009	5.58	9	2009
8	2009	8/13/2009	4.4273	9	2009	9/22/2009	5.61	9	2009	9/22/2009	5.54	9	2009
8	2009	8/14/2009	4.4206	9	2009	9/23/2009	5.59	9	2009	9/23/2009	5.53	9	2009
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8	2009	8/18/2009	4.3527	9	2009	9/25/2009	5.5	9	2009	9/25/2009	5.43	9	2009
8	2009	8/19/2009	4.2914	9	2009	9/28/2009	5.46	9	2009	9/28/2009	5.39	9	2009
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8	2009	8/21/2009	4.3748	9	2009	9/30/2009	5.49	9	2009	9/30/2009	5.41	9	2009
8	2009	8/24/2009	4.2659	10	2009	10/1/2009	5.43	10	2009	10/1/2009	5.33	10	2009
8	2009	8/25/2009	4.2228	10	2009	10/2/2009	5.49	10	2009	10/2/2009	5.39	10	2009
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8	2009	8/27/2009	4.2236	10	2009	10/6/2009	5.53	10	2009	10/6/2009	5.44	10	2009
8	2009	8/28/2009	4.2004	10	2009	10/7/2009	5.46	10	2009	10/7/2009	5.36	10	2009
8	2009	8/31/2009	4.1782	10	2009	10/8/2009	5.56	10	2009	10/8/2009	5.47	10	2009
9	2009	9/1/2009	4.1923	10	2009	10/9/2009	5.69	10	2009	10/9/2009	5.6	10	2009
9	2009	9/2/2009	4.1201	10	2009	10/13/2009	5.62	10	2009	10/13/2009	5.53	10	2009
9	2009	9/3/2009	4.1604	10	2009	10/14/2009	5.73	10	2009	10/14/2009	5.64	10	2009
9	2009	9/4/2009	4.2666	10	2009	10/15/2009	5.76	10	2009	10/15/2009	5.68	10	2009
9	2009	9/7/2009	4.2693	10	2009	10/16/2009	5.68	10	2009	10/16/2009	5.61	10	2009
9	2009	9/8/2009	4.3184	10	2009	10/19/2009	5.65	10	2009	10/19/2009	5.58	10	2009
9	2009	9/9/2009	4.3285	10	2009	10/20/2009	5.59	10	2009	10/20/2009	5.51	10	2009
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9	2009	9/21/2009	4.2348	10	2009	10/30/2009	5.62	10	2009	10/30/2009	5.55	10	2009
9	2009	9/22/2009	4.1964	11	2009	11/2/2009	5.66	11	2009	11/2/2009	5.59	11	2009

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9	2009	9/28/2009	4.0322	11	2009	11/6/2009	5.75	11	2009	11/6/2009	5.7	11	2009
9	2009	9/29/2009	4.0176	11	2009	11/9/2009	5.76	11	2009	11/9/2009	5.71	11	2009
9	2009	9/30/2009	4.0501	11	2009	11/10/2009	5.77	11	2009	11/10/2009	5.72	11	2009
10	2009	10/1/2009	3.9557	11	2009	11/12/2009	5.74	11	2009	11/12/2009	5.68	11	2009
10	2009	10/2/2009	3.9962	11	2009	11/13/2009	5.71	11	2009	11/13/2009	5.64	11	2009
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10	2009	10/7/2009	4.0021	11	2009	11/18/2009	5.65	11	2009	11/18/2009	5.6	11	2009
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10	2009	10/9/2009	4.2229	11	2009	11/20/2009	5.65	11	2009	11/20/2009	5.63	11	2009
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11	2009	11/11/2009	4.4124	12	2009	12/24/2009	5.91	12	2009	12/24/2009	5.94	12	2009
11	2009	11/12/2009	4.3909	12	2009	12/28/2009	5.93	12	2009	12/28/2009	5.95	12	2009
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12	2009	12/9/2009	4.4184	1	2010	1/26/2010	5.77	1	2010	1/26/2010	5.77	1	2010
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1	2010	1/20/2010	4.5342	3	2010	3/10/2010	5.85	3	2010	3/10/2010	5.89	3	2010
1	2010	1/21/2010	4.4932	3	2010	3/11/2010	5.82	3	2010	3/11/2010	5.86	3	2010
1	2010	1/22/2010	4.5312	3	2010	3/12/2010	5.79	3	2010	3/12/2010	5.83	3	2010
1	2010	1/25/2010	4.5469	3	2010	3/15/2010	5.8	3	2010	3/15/2010	5.84	3	2010
1	2010	1/26/2010	4.5528	3	2010	3/16/2010	5.75	3	2010	3/16/2010	5.79	3	2010
1	2010	1/27/2010	4.5627	3	2010	3/17/2010	5.72	3	2010	3/17/2010	5.76	3	2010
1	2010	1/28/2010	4.5489	3	2010	3/18/2010	5.74	3	2010	3/18/2010	5.78	3	2010
1	2010	1/29/2010	4.4884	3	2010	3/19/2010	5.73	3	2010	3/19/2010	5.77	3	2010
2	2010	2/1/2010	4.5617	3	2010	3/22/2010	5.72	3	2010	3/22/2010	5.76	3	2010
2	2010	2/2/2010	4.5588	3	2010	3/23/2010	5.75	3	2010	3/23/2010	5.78	3	2010
2	2010	2/3/2010	4.6383	3	2010	3/24/2010	5.87	3	2010	3/24/2010	5.9	3	2010
2	2010	2/4/2010	4.5499	3	2010	3/25/2010	5.93	3	2010	3/25/2010	5.96	3	2010
2	2010	2/5/2010	4.5186	3	2010	3/26/2010	5.89	3	2010	3/26/2010	5.93	3	2010
2	2010	2/8/2010	4.4972	3	2010	3/29/2010	5.9	3	2010	3/29/2010	5.94	3	2010
2	2010	2/9/2010	4.5835	3	2010	3/30/2010	5.9	3	2010	3/30/2010	5.94	3	2010
2	2010	2/10/2010	4.6364	3	2010	3/31/2010	5.85	3	2010	3/31/2010	5.89	3	2010
2	2010	2/11/2010	4.6646	4	2010	4/1/2010	5.86	4	2010	4/1/2010	5.91	4	2010
2	2010	2/12/2010	4.6463	4	2010	4/2/2010	5.93	4	2010	4/2/2010	5.98	4	2010
2	2010	2/15/2010	4.6493	4	2010	4/5/2010	5.97	4	2010	4/5/2010	6.02	4	2010
2	2010	2/16/2010	4.6318	4	2010	4/6/2010	5.97	4	2010	4/6/2010	6.01	4	2010
2	2010	2/17/2010	4.6972	4	2010	4/7/2010	5.87	4	2010	4/7/2010	5.91	4	2010
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3	2010	3/25/2010	4.7577	5	2010	5/13/2010	5.64	5	2010	5/13/2010	5.65	5	2010
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4	2010	4/13/2010	4.6813	6	2010	6/2/2010	5.63	6	2010	6/2/2010	5.6	6	2010
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4	2010	4/22/2010	4.6363	6	2010	6/11/2010	5.55	6	2010	6/11/2010	5.48	6	2010
4	2010	4/23/2010	4.6597	6	2010	6/14/2010	5.62	6	2010	6/14/2010	5.54	6	2010
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5	2010	5/13/2010	4.4271	7	2010	7/2/2010	5.31	7	2010	7/2/2010	5.24	7	2010
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5	2010	5/17/2010	4.359	7	2010	7/7/2010	5.34	7	2010	7/7/2010	5.25	7	2010
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5	2010	5/20/2010	4.0878	7	2010	7/12/2010	5.41	7	2010	7/12/2010	5.34	7	2010
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6	2010	6/24/2010	4.1039	8	2010	8/16/2010	4.95	8	2010	8/16/2010	4.91	8	2010
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7	2010	7/1/2010	3.8944	8	2010	8/23/2010	4.92	8	2010	8/23/2010	4.86	8	2010
7	2010	7/2/2010	3.9425	8	2010	8/24/2010	4.83	8	2010	8/24/2010	4.8	8	2010
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7	2010	7/6/2010	3.89	8	2010	8/26/2010	4.82	8	2010	8/26/2010	4.78	8	2010
7	2010	7/7/2010	3.9569	8	2010	8/27/2010	4.98	8	2010	8/27/2010	4.94	8	2010
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7	2010	7/9/2010	4.0361	8	2010	8/31/2010	4.84	8	2010	8/31/2010	4.78	8	2010
7	2010	7/12/2010	4.0561	9	2010	9/1/2010	4.96	9	2010	9/1/2010	4.91	9	2010
7	2010	7/13/2010	4.1062	9	2010	9/2/2010	5.02	9	2010	9/2/2010	4.97	9	2010

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8	2010	8/2/2010	4.0619	9	2010	9/23/2010	5	9	2010	9/23/2010	4.97	9	2010
8	2010	8/3/2010	4.0488	9	2010	9/24/2010	5.07	9	2010	9/24/2010	5.03	9	2010
8	2010	8/4/2010	4.0795	9	2010	9/27/2010	4.98	9	2010	9/27/2010	4.94	9	2010
8	2010	8/5/2010	4.0505	9	2010	9/28/2010	4.94	9	2010	9/28/2010	4.88	9	2010
8	2010	8/6/2010	3.994	9	2010	9/29/2010	4.98	9	2010	9/29/2010	4.93	9	2010
8	2010	8/9/2010	4.0165	9	2010	9/30/2010	4.99	9	2010	9/30/2010	4.93	9	2010
8	2010	8/10/2010	4.0044	10	2010	10/1/2010	5.02	10	2010	10/1/2010	4.96	10	2010
8	2010	8/11/2010	3.9188	10	2010	10/4/2010	5.02	10	2010	10/4/2010	4.96	10	2010
8	2010	8/12/2010	3.9476	10	2010	10/5/2010	5.03	10	2010	10/5/2010	4.98	10	2010
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8	2010	8/17/2010	3.7632	10	2010	10/8/2010	5.04	10	2010	10/8/2010	4.99	10	2010
8	2010	8/18/2010	3.7331	10	2010	10/12/2010	5.09	10	2010	10/12/2010	5.04	10	2010
8	2010	8/19/2010	3.6543	10	2010	10/13/2010	5.11	10	2010	10/13/2010	5.07	10	2010
8	2010	8/20/2010	3.6601	10	2010	10/14/2010	5.18	10	2010	10/14/2010	5.14	10	2010
8	2010	8/23/2010	3.6618	10	2010	10/15/2010	5.27	10	2010	10/15/2010	5.23	10	2010
8	2010	8/24/2010	3.5605	10	2010	10/18/2010	5.21	10	2010	10/18/2010	5.15	10	2010
8	2010	8/25/2010	3.5695	10	2010	10/19/2010	5.18	10	2010	10/19/2010	5.13	10	2010
8	2010	8/26/2010	3.5115	10	2010	10/20/2010	5.16	10	2010	10/20/2010	5.11	10	2010
8	2010	8/27/2010	3.6896	10	2010	10/21/2010	5.2	10	2010	10/21/2010	5.17	10	2010
8	2010	8/30/2010	3.5809	10	2010	10/22/2010	5.2	10	2010	10/22/2010	5.17	10	2010
8	2010	8/31/2010	3.5155	10	2010	10/25/2010	5.16	10	2010	10/25/2010	5.13	10	2010
9	2010	9/1/2010	3.6457	10	2010	10/26/2010	5.25	10	2010	10/26/2010	5.22	10	2010
9	2010	9/2/2010	3.7141	10	2010	10/27/2010	5.28	10	2010	10/27/2010	5.26	10	2010
9	2010	9/3/2010	3.7811	10	2010	10/28/2010	5.3	10	2010	10/28/2010	5.27	10	2010
9	2010	9/6/2010	3.7837	10	2010	10/29/2010	5.23	10	2010	10/29/2010	5.21	10	2010
9	2010	9/7/2010	3.6616	11	2010	11/1/2010	5.24	11	2010	11/1/2010	5.22	11	2010
9	2010	9/8/2010	3.7294	11	2010	11/2/2010	5.16	11	2010	11/2/2010	5.14	11	2010
9	2010	9/9/2010	3.8387	11	2010	11/3/2010	5.28	11	2010	11/3/2010	5.26	11	2010

9	2010	9/10/2010	3.8687	11	2010	11/4/2010	5.24	11	2010	11/4/2010	5.23	11	2010
9	2010	9/13/2010	3.8483	11	2010	11/5/2010	5.31	11	2010	11/5/2010	5.31	11	2010
9	2010	9/14/2010	3.7993	11	2010	11/8/2010	5.31	11	2010	11/8/2010	5.32	11	2010
9	2010	9/15/2010	3.8713	11	2010	11/9/2010	5.42	11	2010	11/9/2010	5.42	11	2010
9	2010	9/16/2010	3.9248	11	2010	11/10/2010	5.41	11	2010	11/10/2010	5.41	11	2010
9	2010	9/17/2010	3.9033	11	2010	11/11/2010	5.42	11	2010	11/11/2010	5.42	11	2010
9	2010	9/20/2010	3.8757	11	2010	11/12/2010	5.44	11	2010	11/12/2010	5.44	11	2010
9	2010	9/21/2010	3.7845	11	2010	11/15/2010	5.56	11	2010	11/15/2010	5.55	11	2010
9	2010	9/22/2010	3.7499	11	2010	11/16/2010	5.45	11	2010	11/16/2010	5.44	11	2010
9	2010	9/23/2010	3.7301	11	2010	11/17/2010	5.47	11	2010	11/17/2010	5.46	11	2010
9	2010	9/24/2010	3.794	11	2010	11/18/2010	5.47	11	2010	11/18/2010	5.47	11	2010
9	2010	9/27/2010	3.7181	11	2010	11/19/2010	5.43	11	2010	11/19/2010	5.43	11	2010
9	2010	9/28/2010	3.6579	11	2010	11/22/2010	5.39	11	2010	11/22/2010	5.38	11	2010
9	2010	9/29/2010	3.6841	11	2010	11/23/2010	5.35	11	2010	11/23/2010	5.35	11	2010
9	2010	9/30/2010	3.6849	11	2010	11/24/2010	5.48	11	2010	11/24/2010	5.47	11	2010
10	2010	10/1/2010	3.7147	11	2010	11/26/2010	5.38	11	2010	11/26/2010	5.38	11	2010
10	2010	10/4/2010	3.7061	11	2010	11/29/2010	5.33	11	2010	11/29/2010	5.33	11	2010
10	2010	10/5/2010	3.7472	11	2010	11/30/2010	5.29	11	2010	11/30/2010	5.28	11	2010
10	2010	10/6/2010	3.6747	12	2010	12/1/2010	5.42	12	2010	12/1/2010	5.41	12	2010
10	2010	10/7/2010	3.7121	12	2010	12/2/2010	5.44	12	2010	12/2/2010	5.44	12	2010
10	2010	10/8/2010	3.7489	12	2010	12/3/2010	5.49	12	2010	12/3/2010	5.48	12	2010
10	2010	10/11/2010	3.7489	12	2010	12/6/2010	5.42	12	2010	12/6/2010	5.42	12	2010
10	2010	10/12/2010	3.8192	12	2010	12/7/2010	5.59	12	2010	12/7/2010	5.59	12	2010
10	2010	10/13/2010	3.8166	12	2010	12/8/2010	5.6	12	2010	12/8/2010	5.61	12	2010
10	2010	10/14/2010	3.9149	12	2010	12/9/2010	5.54	12	2010	12/9/2010	5.56	12	2010
10	2010	10/15/2010	3.9791	12	2010	12/10/2010	5.57	12	2010	12/10/2010	5.58	12	2010
10	2010	10/18/2010	3.9537	12	2010	12/13/2010	5.54	12	2010	12/13/2010	5.56	12	2010
10	2010	10/19/2010	3.9131	12	2010	12/14/2010	5.69	12	2010	12/14/2010	5.7	12	2010
10	2010	10/20/2010	3.8899	12	2010	12/15/2010	5.73	12	2010	12/15/2010	5.74	12	2010
10	2010	10/21/2010	3.9609	12	2010	12/16/2010	5.69	12	2010	12/16/2010	5.71	12	2010
10	2010	10/22/2010	3.9293	12	2010	12/17/2010	5.52	12	2010	12/17/2010	5.54	12	2010
10	2010	10/25/2010	3.9095	12	2010	12/20/2010	5.56	12	2010	12/20/2010	5.58	12	2010
10	2010	10/26/2010	3.9946	12	2010	12/21/2010	5.53	12	2010	12/21/2010	5.55	12	2010
10	2010	10/27/2010	4.0564	12	2010	12/22/2010	5.55	12	2010	12/22/2010	5.56	12	2010
10	2010	10/28/2010	4.049	12	2010	12/23/2010	5.57	12	2010	12/23/2010	5.58	12	2010
10	2010	10/29/2010	3.9828	12	2010	12/27/2010	5.52	12	2010	12/27/2010	5.53	12	2010
11	2010	11/1/2010	4.0029	12	2010	12/28/2010	5.64	12	2010	12/28/2010	5.65	12	2010
11	2010	11/2/2010	3.9266	12	2010	12/29/2010	5.5	12	2010	12/29/2010	5.52	12	2010
11	2010	11/3/2010	4.0398	12	2010	12/30/2010	5.52	12	2010	12/30/2010	5.54	12	2010
11	2010	11/4/2010	4.0713	12	2010	12/31/2010	5.44	12	2010	12/31/2010	5.45	12	2010
11	2010	11/5/2010	4.1192	1	2011	1/3/2011	5.49	1	2011	1/3/2011	5.5	1	2011
11	2010	11/8/2010	4.1201	1	2011	1/4/2011	5.52	1	2011	1/4/2011	5.53	1	2011

11	2010	11/9/2010	4.2466	1	2011	1/5/2011	5.61	1	2011	1/5/2011	5.63	1	2011
11	2010	11/10/2010	4.2311	1	2011	1/6/2011	5.57	1	2011	1/6/2011	5.59	1	2011
11	2010	11/11/2010	4.243	1	2011	1/7/2011	5.53	1	2011	1/7/2011	5.55	1	2011
11	2010	11/12/2010	4.2844	1	2011	1/10/2011	5.52	1	2011	1/10/2011	5.54	1	2011
11	2010	11/15/2010	4.4153	1	2011	1/11/2011	5.51	1	2011	1/11/2011	5.53	1	2011
11	2010	11/16/2010	4.2648	1	2011	1/12/2011	5.54	1	2011	1/12/2011	5.55	1	2011
11	2010	11/17/2010	4.2853	1	2011	1/13/2011	5.52	1	2011	1/13/2011	5.53	1	2011
11	2010	11/18/2010	4.2807	1	2011	1/14/2011	5.55	1	2011	1/14/2011	5.56	1	2011
11	2010	11/19/2010	4.2444	1	2011	1/18/2011	5.58	1	2011	1/18/2011	5.59	1	2011
11	2010	11/22/2010	4.2048	1	2011	1/19/2011	5.54	1	2011	1/19/2011	5.56	1	2011
11	2010	11/23/2010	4.1901	1	2011	1/20/2011	5.64	1	2011	1/20/2011	5.65	1	2011
11	2010	11/24/2010	4.2797	1	2011	1/21/2011	5.59	1	2011	1/21/2011	5.6	1	2011
11	2010	11/25/2010	4.275	1	2011	1/24/2011	5.57	1	2011	1/24/2011	5.59	1	2011
11	2010	11/26/2010	4.2093	1	2011	1/25/2011	5.49	1	2011	1/25/2011	5.5	1	2011
11	2010	11/29/2010	4.1401	1	2011	1/26/2011	5.62	1	2011	1/26/2011	5.63	1	2011
11	2010	11/30/2010	4.1104	1	2011	1/27/2011	5.58	1	2011	1/27/2011	5.59	1	2011
12	2010	12/1/2010	4.2397	1	2011	1/28/2011	5.55	1	2011	1/28/2011	5.56	1	2011
12	2010	12/2/2010	4.2545	1	2011	1/31/2011	5.6	1	2011	1/31/2011	5.61	1	2011
12	2010	12/3/2010	4.3143	2	2011	2/1/2011	5.63	2	2011	2/1/2011	5.65	2	2011
12	2010	12/6/2010	4.2397	2	2011	2/2/2011	5.65	2	2011	2/2/2011	5.67	2	2011
12	2010	12/7/2010	4.3674	2	2011	2/3/2011	5.68	2	2011	2/3/2011	5.7	2	2011
12	2010	12/8/2010	4.4561	2	2011	2/4/2011	5.75	2	2011	2/4/2011	5.77	2	2011
12	2010	12/9/2010	4.398	2	2011	2/7/2011	5.72	2	2011	2/7/2011	5.74	2	2011
12	2010	12/10/2010	4.4289	2	2011	2/8/2011	5.77	2	2011	2/8/2011	5.79	2	2011
12	2010	12/13/2010	4.4076	2	2011	2/9/2011	5.69	2	2011	2/9/2011	5.72	2	2011
12	2010	12/14/2010	4.5288	2	2011	2/10/2011	5.77	2	2011	2/10/2011	5.8	2	2011
12	2010	12/15/2010	4.5947	2	2011	2/11/2011	5.71	2	2011	2/11/2011	5.75	2	2011
12	2010	12/16/2010	4.5338	2	2011	2/14/2011	5.66	2	2011	2/14/2011	5.69	2	2011
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12	2010	12/20/2010	4.4415	2	2011	2/16/2011	5.67	2	2011	2/16/2011	5.69	2	2011
12	2010	12/21/2010	4.4183	2	2011	2/17/2011	5.66	2	2011	2/17/2011	5.67	2	2011
12	2010	12/22/2010	4.4464	2	2011	2/18/2011	5.7	2	2011	2/18/2011	5.71	2	2011
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12	2010	12/29/2010	4.4309	2	2011	2/28/2011	5.51	2	2011	2/28/2011	5.51	2	2011
12	2010	12/30/2010	4.4231	3	2011	3/1/2011	5.51	3	2011	3/1/2011	5.52	3	2011
12	2010	12/31/2010	4.3341	3	2011	3/2/2011	5.57	3	2011	3/2/2011	5.58	3	2011
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3	2011	3/18/2011	4.4166	5	2011	5/19/2011	5.33	5	2011	5/19/2011	5.32	5	2011
3	2011	3/21/2011	4.4514	5	2011	5/20/2011	5.33	5	2011	5/20/2011	5.32	5	2011
3	2011	3/22/2011	4.4367	5	2011	5/23/2011	5.3	5	2011	5/23/2011	5.29	5	2011
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3	2011	3/31/2011	4.5076	6	2011	6/2/2011	5.31	6	2011	6/2/2011	5.27	6	2011
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5	2011	5/2/2011	4.3786	7	2011	7/5/2011	5.45	7	2011	7/5/2011	5.4	7	2011
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5	2011	5/6/2011	4.2855	7	2011	7/11/2011	5.24	7	2011	7/11/2011	5.21	7	2011
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5	2011	5/10/2011	4.3506	7	2011	7/13/2011	5.21	7	2011	7/13/2011	5.19	7	2011
5	2011	5/11/2011	4.3032	7	2011	7/14/2011	5.27	7	2011	7/14/2011	5.25	7	2011
5	2011	5/12/2011	4.3469	7	2011	7/15/2011	5.28	7	2011	7/15/2011	5.25	7	2011
5	2011	5/13/2011	4.3078	7	2011	7/18/2011	5.31	7	2011	7/18/2011	5.28	7	2011
5	2011	5/16/2011	4.2719	7	2011	7/19/2011	5.22	7	2011	7/19/2011	5.19	7	2011
5	2011	5/17/2011	4.2271	7	2011	7/20/2011	5.29	7	2011	7/20/2011	5.26	7	2011
5	2011	5/18/2011	4.2949	7	2011	7/21/2011	5.33	7	2011	7/21/2011	5.3	7	2011
5	2011	5/19/2011	4.3032	7	2011	7/22/2011	5.27	7	2011	7/22/2011	5.24	7	2011
5	2011	5/20/2011	4.2976	7	2011	7/25/2011	5.33	7	2011	7/25/2011	5.3	7	2011
5	2011	5/23/2011	4.2663	7	2011	7/26/2011	5.28	7	2011	7/26/2011	5.24	7	2011
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5	2011	5/26/2011	4.2225	7	2011	7/29/2011	5.12	7	2011	7/29/2011	5.09	7	2011
5	2011	5/27/2011	4.2424	8	2011	8/1/2011	5.04	8	2011	8/1/2011	5.02	8	2011
5	2011	5/30/2011	4.2424	8	2011	8/2/2011	4.89	8	2011	8/2/2011	4.87	8	2011
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6	2011	6/1/2011	4.1415	8	2011	8/4/2011	4.72	8	2011	8/4/2011	4.67	8	2011
6	2011	6/2/2011	4.2442	8	2011	8/5/2011	4.83	8	2011	8/5/2011	4.77	8	2011
6	2011	6/3/2011	4.2224	8	2011	8/8/2011	4.75	8	2011	8/8/2011	4.67	8	2011
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6	2011	6/7/2011	4.2579	8	2011	8/10/2011	4.65	8	2011	8/10/2011	4.54	8	2011
6	2011	6/8/2011	4.1853	8	2011	8/11/2011	4.92	8	2011	8/11/2011	4.8	8	2011
6	2011	6/9/2011	4.215	8	2011	8/12/2011	4.81	8	2011	8/12/2011	4.71	8	2011
6	2011	6/10/2011	4.1816	8	2011	8/15/2011	4.87	8	2011	8/15/2011	4.77	8	2011
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6	2011	6/14/2011	4.2964	8	2011	8/17/2011	4.73	8	2011	8/17/2011	4.6	8	2011
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6	2011	6/23/2011	4.168	8	2011	8/26/2011	4.8	8	2011	8/26/2011	4.67	8	2011
6	2011	6/24/2011	4.1832	8	2011	8/29/2011	4.89	8	2011	8/29/2011	4.76	8	2011
6	2011	6/27/2011	4.2954	8	2011	8/30/2011	4.78	8	2011	8/30/2011	4.66	8	2011
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6	2011	6/29/2011	4.3766	9	2011	9/1/2011	4.78	9	2011	9/1/2011	4.67	9	2011
6	2011	6/30/2011	4.371	9	2011	9/2/2011	4.59	9	2011	9/2/2011	4.47	9	2011

7	2011	7/1/2011	4.3908	9	2011	9/6/2011	4.57	9	2011	9/6/2011	4.44	9	2011
7	2011	7/4/2011	4.3908	9	2011	9/7/2011	4.66	9	2011	9/7/2011	4.55	9	2011
7	2011	7/5/2011	4.3728	9	2011	9/8/2011	4.63	9	2011	9/8/2011	4.52	9	2011
7	2011	7/6/2011	4.3625	9	2011	9/9/2011	4.57	9	2011	9/9/2011	4.46	9	2011
7	2011	7/7/2011	4.3662	9	2011	9/12/2011	4.58	9	2011	9/12/2011	4.45	9	2011
7	2011	7/8/2011	4.2824	9	2011	9/13/2011	4.67	9	2011	9/13/2011	4.55	9	2011
7	2011	7/11/2011	4.2083	9	2011	9/14/2011	4.67	9	2011	9/14/2011	4.56	9	2011
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7	2011	7/14/2011	4.2539	9	2011	9/19/2011	4.59	9	2011	9/19/2011	4.48	9	2011
7	2011	7/15/2011	4.2465	9	2011	9/20/2011	4.61	9	2011	9/20/2011	4.5	9	2011
7	2011	7/18/2011	4.3083	9	2011	9/21/2011	4.46	9	2011	9/21/2011	4.33	9	2011
7	2011	7/19/2011	4.1902	9	2011	9/22/2011	4.34	9	2011	9/22/2011	4.23	9	2011
7	2011	7/20/2011	4.252	9	2011	9/23/2011	4.44	9	2011	9/23/2011	4.32	9	2011
7	2011	7/21/2011	4.312	9	2011	9/26/2011	4.58	9	2011	9/26/2011	4.47	9	2011
7	2011	7/22/2011	4.2575	9	2011	9/27/2011	4.69	9	2011	9/27/2011	4.58	9	2011
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7	2011	7/27/2011	4.2851	9	2011	9/30/2011	4.49	9	2011	9/30/2011	4.38	9	2011
7	2011	7/28/2011	4.2556	10	2011	10/3/2011	4.35	10	2011	10/3/2011	4.22	10	2011
7	2011	7/29/2011	4.1184	10	2011	10/4/2011	4.36	10	2011	10/4/2011	4.23	10	2011
8	2011	8/1/2011	4.0795	10	2011	10/5/2011	4.49	10	2011	10/5/2011	4.35	10	2011
8	2011	8/2/2011	3.9088	10	2011	10/6/2011	4.56	10	2011	10/6/2011	4.42	10	2011
8	2011	8/3/2011	3.902	10	2011	10/7/2011	4.62	10	2011	10/7/2011	4.48	10	2011
8	2011	8/4/2011	3.6707	10	2011	10/11/2011	4.7	10	2011	10/11/2011	4.57	10	2011
8	2011	8/5/2011	3.8458	10	2011	10/12/2011	4.77	10	2011	10/12/2011	4.66	10	2011
8	2011	8/8/2011	3.653	10	2011	10/13/2011	4.69	10	2011	10/13/2011	4.58	10	2011
8	2011	8/9/2011	3.6181	10	2011	10/14/2011	4.74	10	2011	10/14/2011	4.64	10	2011
8	2011	8/10/2011	3.5146	10	2011	10/17/2011	4.65	10	2011	10/17/2011	4.56	10	2011
8	2011	8/11/2011	3.769	10	2011	10/18/2011	4.63	10	2011	10/18/2011	4.56	10	2011
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8	2011	8/15/2011	3.771	10	2011	10/20/2011	4.63	10	2011	10/20/2011	4.57	10	2011
8	2011	8/16/2011	3.6671	10	2011	10/21/2011	4.66	10	2011	10/21/2011	4.62	10	2011
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8	2011	8/18/2011	3.4193	10	2011	10/25/2011	4.52	10	2011	10/25/2011	4.49	10	2011
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8	2011	8/23/2011	3.4931	10	2011	10/28/2011	4.61	10	2011	10/28/2011	4.57	10	2011
8	2011	8/24/2011	3.6534	10	2011	10/31/2011	4.46	10	2011	10/31/2011	4.42	10	2011
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8	2011	8/26/2011	3.535	11	2011	11/2/2011	4.33	11	2011	11/2/2011	4.24	11	2011
8	2011	8/29/2011	3.5916	11	2011	11/3/2011	4.41	11	2011	11/3/2011	4.32	11	2011

8	2011	8/30/2011	3.5225	11	2011	11/4/2011	4.39	11	2011	11/4/2011	4.3	11	2011
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9	2011	9/1/2011	3.4945	11	2011	11/8/2011	4.42	11	2011	11/8/2011	4.32	11	2011
9	2011	9/2/2011	3.2969	11	2011	11/9/2011	4.33	11	2011	11/9/2011	4.21	11	2011
9	2011	9/5/2011	3.2969	11	2011	11/10/2011	4.44	11	2011	11/10/2011	4.32	11	2011
9	2011	9/6/2011	3.272	11	2011	11/14/2011	4.43	11	2011	11/14/2011	4.3	11	2011
9	2011	9/7/2011	3.367	11	2011	11/15/2011	4.46	11	2011	11/15/2011	4.32	11	2011
9	2011	9/8/2011	3.3086	11	2011	11/16/2011	4.43	11	2011	11/16/2011	4.28	11	2011
9	2011	9/9/2011	3.2463	11	2011	11/17/2011	4.36	11	2011	11/17/2011	4.21	11	2011
9	2011	9/12/2011	3.2509	11	2011	11/18/2011	4.41	11	2011	11/18/2011	4.23	11	2011
9	2011	9/13/2011	3.3273	11	2011	11/21/2011	4.36	11	2011	11/21/2011	4.19	11	2011
9	2011	9/14/2011	3.271	11	2011	11/22/2011	4.35	11	2011	11/22/2011	4.17	11	2011
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9	2011	9/16/2011	3.313	11	2011	11/25/2011	4.38	11	2011	11/25/2011	4.19	11	2011
9	2011	9/19/2011	3.2184	11	2011	11/28/2011	4.4	11	2011	11/28/2011	4.19	11	2011
9	2011	9/20/2011	3.2024	11	2011	11/29/2011	4.46	11	2011	11/29/2011	4.28	11	2011
9	2011	9/21/2011	2.9942	11	2011	11/30/2011	4.57	11	2011	11/30/2011	4.38	11	2011
9	2011	9/22/2011	2.7977	12	2011	12/1/2011	4.64	12	2011	12/1/2011	4.46	12	2011
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9	2011	9/29/2011	3.0537	12	2011	12/8/2011	4.48	12	2011	12/8/2011	4.35	12	2011
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12	2011	12/29/2011	2.9025	3	2012	3/14/2012	4.67	3	2012	3/14/2012	4.6	3	2012
12	2011	12/30/2011	2.8941	3	2012	3/15/2012	4.67	3	2012	3/15/2012	4.6	3	2012
1	2012	1/2/2012	2.8941	3	2012	3/16/2012	4.67	3	2012	3/16/2012	4.6	3	2012
1	2012	1/3/2012	2.9812	3	2012	3/19/2012	4.74	3	2012	3/19/2012	4.67	3	2012
1	2012	1/4/2012	3.0274	3	2012	3/20/2012	4.71	3	2012	3/20/2012	4.65	3	2012
1	2012	1/5/2012	3.0607	3	2012	3/21/2012	4.63	3	2012	3/21/2012	4.57	3	2012
1	2012	1/6/2012	3.0156	3	2012	3/22/2012	4.62	3	2012	3/22/2012	4.56	3	2012
1	2012	1/9/2012	3.0266	3	2012	3/23/2012	4.57	3	2012	3/23/2012	4.51	3	2012
1	2012	1/10/2012	3.0242	3	2012	3/26/2012	4.59	3	2012	3/26/2012	4.52	3	2012
1	2012	1/11/2012	2.9632	3	2012	3/27/2012	4.56	3	2012	3/27/2012	4.49	3	2012
1	2012	1/12/2012	2.971	3	2012	3/28/2012	4.57	3	2012	3/28/2012	4.5	3	2012
1	2012	1/13/2012	2.91	3	2012	3/29/2012	4.54	3	2012	3/29/2012	4.47	3	2012
1	2012	1/16/2012	2.91	3	2012	3/30/2012	4.61	3	2012	3/30/2012	4.54	3	2012
1	2012	1/17/2012	2.8985	4	2012	4/2/2012	4.61	4	2012	4/2/2012	4.53	4	2012
1	2012	1/18/2012	2.9562	4	2012	4/3/2012	4.67	4	2012	4/3/2012	4.6	4	2012
1	2012	1/19/2012	3.0416	4	2012	4/4/2012	4.64	4	2012	4/4/2012	4.57	4	2012
1	2012	1/20/2012	3.0998	4	2012	4/5/2012	4.59	4	2012	4/5/2012	4.52	4	2012
1	2012	1/23/2012	3.1297	4	2012	4/6/2012	4.51	4	2012	4/6/2012	4.44	4	2012
1	2012	1/24/2012	3.1492	4	2012	4/9/2012	4.48	4	2012	4/9/2012	4.4	4	2012
1	2012	1/25/2012	3.1484	4	2012	4/10/2012	4.45	4	2012	4/10/2012	4.36	4	2012
1	2012	1/26/2012	3.0902	4	2012	4/11/2012	4.5	4	2012	4/11/2012	4.41	4	2012
1	2012	1/27/2012	3.0574	4	2012	4/12/2012	4.52	4	2012	4/12/2012	4.43	4	2012
1	2012	1/30/2012	2.9989	4	2012	4/13/2012	4.46	4	2012	4/13/2012	4.37	4	2012
1	2012	1/31/2012	2.9375	4	2012	4/16/2012	4.43	4	2012	4/16/2012	4.33	4	2012
2	2012	2/1/2012	2.9919	4	2012	4/17/2012	4.47	4	2012	4/17/2012	4.37	4	2012
2	2012	2/2/2012	3.0028	4	2012	4/18/2012	4.44	4	2012	4/18/2012	4.35	4	2012
2	2012	2/3/2012	3.1192	4	2012	4/19/2012	4.43	4	2012	4/19/2012	4.33	4	2012
2	2012	2/6/2012	3.0966	4	2012	4/20/2012	4.45	4	2012	4/20/2012	4.35	4	2012
2	2012	2/7/2012	3.1435	4	2012	4/23/2012	4.41	4	2012	4/23/2012	4.3	4	2012
2	2012	2/8/2012	3.1509	4	2012	4/24/2012	4.45	4	2012	4/24/2012	4.33	4	2012
2	2012	2/9/2012	3.1803	4	2012	4/25/2012	4.47	4	2012	4/25/2012	4.36	4	2012
2	2012	2/10/2012	3.1404	4	2012	4/26/2012	4.46	4	2012	4/26/2012	4.35	4	2012
2	2012	2/13/2012	3.1202	4	2012	4/27/2012	4.44	4	2012	4/27/2012	4.33	4	2012
2	2012	2/14/2012	3.0873	4	2012	4/30/2012	4.44	4	2012	4/30/2012	4.33	4	2012
2	2012	2/15/2012	3.0897	5	2012	5/1/2012	4.49	5	2012	5/1/2012	4.38	5	2012
2	2012	2/16/2012	3.1387	5	2012	5/2/2012	4.44	5	2012	5/2/2012	4.33	5	2012
2	2012	2/17/2012	3.1476	5	2012	5/3/2012	4.44	5	2012	5/3/2012	4.33	5	2012
2	2012	2/20/2012	3.1476	5	2012	5/4/2012	4.4	5	2012	5/4/2012	4.29	5	2012
2	2012	2/21/2012	3.209	5	2012	5/7/2012	4.39	5	2012	5/7/2012	4.28	5	2012

2	2012	2/22/2012	3.1476	5	2012	5/8/2012	4.36	5	2012	5/8/2012	4.24	5	2012
2	2012	2/23/2012	3.1387	5	2012	5/9/2012	4.38	5	2012	5/9/2012	4.26	5	2012
2	2012	2/24/2012	3.0992	5	2012	5/10/2012	4.39	5	2012	5/10/2012	4.27	5	2012
2	2012	2/27/2012	3.0475	5	2012	5/11/2012	4.34	5	2012	5/11/2012	4.22	5	2012
2	2012	2/28/2012	3.0729	5	2012	5/14/2012	4.29	5	2012	5/14/2012	4.16	5	2012
2	2012	2/29/2012	3.0848	5	2012	5/15/2012	4.28	5	2012	5/15/2012	4.16	5	2012
3	2012	3/1/2012	3.1476	5	2012	5/16/2012	4.27	5	2012	5/16/2012	4.16	5	2012
3	2012	3/2/2012	3.1024	5	2012	5/17/2012	4.2	5	2012	5/17/2012	4.07	5	2012
3	2012	3/5/2012	3.15	5	2012	5/18/2012	4.23	5	2012	5/18/2012	4.08	5	2012
3	2012	3/6/2012	3.0736	5	2012	5/21/2012	4.25	5	2012	5/21/2012	4.12	5	2012
3	2012	3/7/2012	3.1233	5	2012	5/22/2012	4.37	5	2012	5/22/2012	4.23	5	2012
3	2012	3/8/2012	3.1745	5	2012	5/23/2012	4.29	5	2012	5/23/2012	4.14	5	2012
3	2012	3/9/2012	3.1778	5	2012	5/24/2012	4.35	5	2012	5/24/2012	4.2	5	2012
3	2012	3/12/2012	3.1712	5	2012	5/25/2012	4.35	5	2012	5/25/2012	4.2	5	2012
3	2012	3/13/2012	3.2663	5	2012	5/29/2012	4.34	5	2012	5/29/2012	4.2	5	2012
3	2012	3/14/2012	3.4009	5	2012	5/30/2012	4.24	5	2012	5/30/2012	4.08	5	2012
3	2012	3/15/2012	3.4148	5	2012	5/31/2012	4.2	5	2012	5/31/2012	4.04	5	2012
3	2012	3/16/2012	3.4061	6	2012	6/1/2012	4.09	6	2012	6/1/2012	3.92	6	2012
3	2012	3/19/2012	3.4779	6	2012	6/4/2012	4.14	6	2012	6/4/2012	3.97	6	2012
3	2012	3/20/2012	3.4454	6	2012	6/5/2012	4.18	6	2012	6/5/2012	4.03	6	2012
3	2012	3/21/2012	3.3837	6	2012	6/6/2012	4.28	6	2012	6/6/2012	4.13	6	2012
3	2012	3/22/2012	3.3596	6	2012	6/7/2012	4.3	6	2012	6/7/2012	4.16	6	2012
3	2012	3/23/2012	3.3051	6	2012	6/8/2012	4.3	6	2012	6/8/2012	4.16	6	2012
3	2012	3/26/2012	3.3391	6	2012	6/11/2012	4.26	6	2012	6/11/2012	4.11	6	2012
3	2012	3/27/2012	3.2975	6	2012	6/12/2012	4.31	6	2012	6/12/2012	4.16	6	2012
3	2012	3/28/2012	3.3102	6	2012	6/13/2012	4.25	6	2012	6/13/2012	4.11	6	2012
3	2012	3/29/2012	3.2731	6	2012	6/14/2012	4.24	6	2012	6/14/2012	4.1	6	2012
3	2012	3/30/2012	3.3358	6	2012	6/15/2012	4.23	6	2012	6/15/2012	4.08	6	2012
4	2012	4/2/2012	3.3281	6	2012	6/18/2012	4.22	6	2012	6/18/2012	4.07	6	2012
4	2012	4/3/2012	3.4404	6	2012	6/19/2012	4.25	6	2012	6/19/2012	4.12	6	2012
4	2012	4/4/2012	3.3572	6	2012	6/20/2012	4.23	6	2012	6/20/2012	4.1	6	2012
4	2012	4/5/2012	3.3265	6	2012	6/21/2012	4.19	6	2012	6/21/2012	4.05	6	2012
4	2012	4/6/2012	3.2157	6	2012	6/22/2012	4.25	6	2012	6/22/2012	4.13	6	2012
4	2012	4/9/2012	3.1959	6	2012	6/25/2012	4.18	6	2012	6/25/2012	4.05	6	2012
4	2012	4/10/2012	3.1281	6	2012	6/26/2012	4.2	6	2012	6/26/2012	4.06	6	2012
4	2012	4/11/2012	3.1959	6	2012	6/27/2012	4.19	6	2012	6/27/2012	4.06	6	2012
4	2012	4/12/2012	3.2116	6	2012	6/28/2012	4.16	6	2012	6/28/2012	4.03	6	2012
4	2012	4/13/2012	3.1273	6	2012	6/29/2012	4.25	6	2012	6/29/2012	4.13	6	2012
4	2012	4/16/2012	3.1305										
4	2012	4/17/2012	3.1411										
4	2012	4/18/2012	3.1265										
4	2012	4/19/2012	3.1208										

4	2012	4/20/2012	3.124
4	2012	4/23/2012	3.0846
4	2012	4/24/2012	3.1281
4	2012	4/25/2012	3.1476
4	2012	4/26/2012	3.1176
4	2012	4/27/2012	3.1224
4	2012	4/30/2012	3.1111
5	2012	5/1/2012	3.146
5	2012	5/2/2012	3.1159
5	2012	5/3/2012	3.1184
5	2012	5/4/2012	3.0709
5	2012	5/7/2012	3.0598
5	2012	5/8/2012	3.0336
5	2012	5/9/2012	3.0249
5	2012	5/10/2012	3.0407
5	2012	5/11/2012	3.0103
5	2012	5/14/2012	2.9199
5	2012	5/15/2012	2.9168
5	2012	5/16/2012	2.8989
5	2012	5/17/2012	2.7869
5	2012	5/18/2012	2.8064
5	2012	5/21/2012	2.8094
5	2012	5/22/2012	2.8665
5	2012	5/23/2012	2.8155
5	2012	5/24/2012	2.8719
5	2012	5/25/2012	2.8412
5	2012	5/28/2012	2.8412
5	2012	5/29/2012	2.8473
5	2012	5/30/2012	2.7137
5	2012	5/31/2012	2.6421
6	2012	6/1/2012	2.5194
6	2012	6/4/2012	2.5652
6	2012	6/5/2012	2.642
6	2012	6/6/2012	2.738
6	2012	6/7/2012	2.7402
6	2012	6/8/2012	2.7454
6	2012	6/11/2012	2.7083
6	2012	6/12/2012	2.7693
6	2012	6/13/2012	2.7083
6	2012	6/14/2012	2.7409
6	2012	6/15/2012	2.684
6	2012	6/18/2012	2.6606

6	2012	6/19/2012	2.7333
6	2012	6/20/2012	2.7356
6	2012	6/21/2012	2.6868
6	2012	6/22/2012	2.7616
6	2012	6/25/2012	2.6765
6	2012	6/26/2012	2.7
6	2012	6/27/2012	2.6918
6	2012	6/28/2012	2.6757
6	2012	6/29/2012	2.7533

Public Utility Bonds (Baa-Rated)				30-Year	Average	Public Utility Bonds		Credit Spreads	
Date	Yield			T-Bonds	Corporate	A-rated	Baa-Rated	A-rated	Baa-Rated
1/2/2007	6.15	1	2007	4.85	5.92	5.96	6.16	1.11	1.31
1/3/2007	6.1	2	2007	4.82	5.88	5.90	6.10	1.08	1.28
1/4/2007	6.06	3	2007	4.72	5.84	5.85	6.10	1.13	1.38
1/5/2007	6.07	4	2007	4.86	5.99	5.97	6.24	1.10	1.37
1/8/2007	6.07	5	2007	4.90	6.00	5.99	6.23	1.08	1.33
1/9/2007	6.07	6	2007	5.21	6.32	6.30	6.54	1.10	1.34
1/10/2007	6.09	7	2007	5.10	6.26	6.25	6.49	1.15	1.39
1/11/2007	6.14	8	2007	4.94	6.26	6.24	6.51	1.30	1.57
1/12/2007	6.17	9	2007	4.79	6.21	6.18	6.45	1.39	1.66
1/16/2007	6.15	10	2007	4.78	6.12	6.11	6.36	1.33	1.58
1/17/2007	6.19	11	2007	4.52	5.97	5.97	6.27	1.45	1.75
1/18/2007	6.15	12	2007	4.53	6.15	6.16	6.51	1.63	1.98
1/19/2007	6.16								
1/22/2007	6.14	1	2008	4.33	6.02	6.02	6.35	1.68	2.01
1/23/2007	6.19	2	2008	4.51	6.24	6.21	6.60	1.70	2.08
1/24/2007	6.2	3	2008	4.38	6.23	6.21	6.68	1.83	2.30
1/25/2007	6.25	4	2008	4.44	6.29	6.29	6.81	1.85	2.37
1/26/2007	6.26	5	2008	4.60	6.31	6.28	6.79	1.68	2.20
1/29/2007	6.27	6	2008	4.68	6.43	6.38	6.93	1.70	2.24
1/30/2007	6.26	7	2008	4.56	6.44	6.40	6.97	1.84	2.41
1/31/2007	6.22	8	2008	4.50	6.42	6.37	6.98	1.87	2.48
2/1/2007	6.23	9	2008	4.27	6.50	6.49	7.15	2.22	2.88
2/2/2007	6.22	10	2008	4.16	7.56	7.56	8.58	3.40	4.42
2/5/2007	6.19	11	2008	3.98	7.65	7.60	8.98	3.62	5.00
2/6/2007	6.15	12	2008	2.85	6.71	6.52	8.11	3.68	5.27
2/7/2007	6.12								
2/8/2007	6.11	1	2009	3.10	6.59	6.39	7.90	3.29	4.80
2/9/2007	6.16	2	2009	3.59	6.64	6.30	7.74	2.71	4.15
2/12/2007	6.17	3	2009	3.64	6.84	6.42	8.00	2.79	4.36
2/13/2007	6.19	4	2009	3.76	6.85	6.48	8.03	2.73	4.27
2/14/2007	6.11	5	2009	4.24	6.79	6.49	7.76	2.25	3.52
2/15/2007	6.08	6	2009	4.51	6.52	6.20	7.30	1.69	2.79
2/16/2007	6.07	7	2009	4.40	6.17	5.97	6.87	1.56	2.47
2/20/2007	6.05	8	2009	4.37	5.83	5.71	6.36	1.34	1.99
2/21/2007	6.06	9	2009	4.19	5.61	5.53	6.12	1.34	1.93
2/22/2007	6.09	10	2009	4.19	5.63	5.55	6.14	1.36	1.95
2/23/2007	6.04	11	2009	4.31	5.68	5.63	6.17	1.32	1.86
2/26/2007	6	12	2009	4.50	5.78	5.79	6.26	1.29	1.76
2/27/2007	5.91								
2/28/2007	6.01	1	2010	4.60	5.76	5.77	6.16	1.17	1.55

3/1/2007	6.02	2	2010	4.62	5.86	5.87	6.25	1.25	1.63
3/2/2007	6	3	2010	4.65	5.81	5.84	6.22	1.20	1.58
3/5/2007	6.02	4	2010	4.69	5.80	5.81	6.19	1.12	1.50
3/6/2007	6.02	5	2010	4.28	5.52	5.50	5.97	1.22	1.69
3/7/2007	6	6	2010	4.12	5.52	5.46	6.18	1.34	2.06
3/8/2007	6.02	7	2010	3.99	5.32	5.26	5.98	1.27	1.99
3/9/2007	6.09	8	2010	3.80	5.05	5.01	5.55	1.21	1.75
3/12/2007	6.05	9	2010	3.77	5.05	5.01	5.53	1.23	1.76
3/13/2007	6.03	10	2010	3.87	5.15	5.10	5.62	1.24	1.75
3/14/2007	6.08	11	2010	4.19	5.37	5.37	5.85	1.18	1.66
3/15/2007	6.08	12	2010	4.42	5.55	5.56	6.04	1.14	1.62
3/16/2007	6.09								
3/19/2007	6.11	1	2011	4.52	5.56	5.57	6.06	1.05	1.54
3/20/2007	6.1	2	2011	4.65	5.66	5.68	6.10	1.03	1.45
3/21/2007	6.09	3	2011	4.51	5.55	5.56	5.97	1.05	1.46
3/22/2007	6.18	4	2011	4.50	5.56	5.55	5.98	1.05	1.48
3/23/2007	6.2	5	2011	4.29	5.33	5.32	5.74	1.03	1.45
3/26/2007	6.18	6	2011	4.23	5.30	5.26	5.67	1.03	1.44
3/27/2007	6.21	7	2011	4.28	5.30	5.27	5.70	0.99	1.42
3/28/2007	6.23	8	2011	3.65	4.79	4.69	5.22	1.04	1.57
3/29/2007	6.22	9	2011	3.18	4.60	4.48	5.11	1.30	1.93
3/30/2007	6.25	10	2011	3.12	4.60	4.52	5.24	1.39	2.12
4/2/2007	6.23	11	2011	3.01	4.39	4.25	4.93	1.24	1.92
4/3/2007	6.25	12	2011	2.99	4.47	4.33	5.07	1.35	2.08
4/4/2007	6.25								
4/5/2007	6.27	1	2012	3.01	4.45	4.34	5.06	1.32	2.05
4/6/2007	6.32	2	2012	3.11	4.42	4.36	5.02	1.25	1.91
4/9/2007	6.32	3	2012	3.28	4.54	4.48	5.13	1.20	1.85
4/10/2007	6.3	4	2012	3.18	4.49	4.40	5.11	1.21	1.93
4/11/2007	6.3	5	2012	2.92	4.33	4.20	4.97	1.28	2.04
4/12/2007	6.3	6	2012	2.70	4.22	4.08	4.91	1.39	2.21
4/13/2007	6.3								
4/16/2007	6.27								
4/17/2007	6.22								
4/18/2007	6.18								
4/19/2007	6.2								
4/20/2007	6.21								
4/23/2007	6.18								
4/24/2007	6.15								
4/25/2007	6.17								
4/26/2007	6.21								
4/27/2007	6.22								

4/30/2007	6.16
5/1/2007	6.15
5/2/2007	6.15
5/3/2007	6.16
5/4/2007	6.13
5/7/2007	6.12
5/8/2007	6.12
5/9/2007	6.16
5/10/2007	6.15
5/11/2007	6.17
5/14/2007	6.19
5/15/2007	6.21
5/16/2007	6.2
5/17/2007	6.24
5/18/2007	6.29
5/21/2007	6.27
5/22/2007	6.31
5/23/2007	6.34
5/24/2007	6.34
5/25/2007	6.33
5/29/2007	6.35
5/30/2007	6.34
5/31/2007	6.35
6/1/2007	6.4
6/4/2007	6.36
6/5/2007	6.4
6/6/2007	6.42
6/7/2007	6.55
6/8/2007	6.59
6/11/2007	6.6
6/12/2007	6.71
6/13/2007	6.63
6/14/2007	6.65
6/15/2007	6.61
6/18/2007	6.6
6/19/2007	6.54
6/20/2007	6.56
6/21/2007	6.61
6/22/2007	6.59
6/25/2007	6.53
6/26/2007	6.55
6/27/2007	6.52

6/28/2007	6.56
6/29/2007	6.46
7/2/2007	6.44
7/3/2007	6.49
7/5/2007	6.58
7/6/2007	6.62
7/9/2007	6.58
7/10/2007	6.47
7/11/2007	6.52
7/12/2007	6.56
7/13/2007	6.54
7/16/2007	6.47
7/17/2007	6.51
7/18/2007	6.45
7/19/2007	6.48
7/20/2007	6.43
7/23/2007	6.43
7/24/2007	6.45
7/25/2007	6.42
7/26/2007	6.41
7/27/2007	6.46
7/30/2007	6.51
7/31/2007	6.46
8/1/2007	6.45
8/2/2007	6.43
8/3/2007	6.4
8/6/2007	6.44
8/7/2007	6.43
8/8/2007	6.55
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8/2/2010	5.8
8/3/2010	5.77
8/4/2010	5.79
8/5/2010	5.77
8/6/2010	5.7
8/9/2010	5.71
8/10/2010	5.73
8/11/2010	5.64
8/12/2010	5.66
8/13/2010	5.6
8/16/2010	5.45
8/17/2010	5.49
8/18/2010	5.46
8/19/2010	5.39
8/20/2010	5.4
8/23/2010	5.41
8/24/2010	5.32
8/25/2010	5.35
8/26/2010	5.33
8/27/2010	5.5
8/30/2010	5.41
8/31/2010	5.36
9/1/2010	5.47
9/2/2010	5.52

9/3/2010	5.57
9/7/2010	5.44
9/8/2010	5.49
9/9/2010	5.61
9/10/2010	5.64
9/13/2010	5.59
9/14/2010	5.52
9/15/2010	5.61
9/16/2010	5.66
9/17/2010	5.65
9/20/2010	5.61
9/21/2010	5.53
9/22/2010	5.48
9/23/2010	5.48
9/24/2010	5.54
9/27/2010	5.45
9/28/2010	5.41
9/29/2010	5.45
9/30/2010	5.45
10/1/2010	5.48
10/4/2010	5.48
10/5/2010	5.5
10/6/2010	5.43
10/7/2010	5.48
10/8/2010	5.52
10/12/2010	5.56
10/13/2010	5.59
10/14/2010	5.67
10/15/2010	5.77
10/18/2010	5.7
10/19/2010	5.67
10/20/2010	5.65
10/21/2010	5.67
10/22/2010	5.67
10/25/2010	5.63
10/26/2010	5.71
10/27/2010	5.75
10/28/2010	5.77
10/29/2010	5.7
11/1/2010	5.72
11/2/2010	5.64
11/3/2010	5.75

11/4/2010	5.72
11/5/2010	5.8
11/8/2010	5.81
11/9/2010	5.92
11/10/2010	5.9
11/11/2010	5.91
11/12/2010	5.94
11/15/2010	6.05
11/16/2010	5.93
11/17/2010	5.95
11/18/2010	5.95
11/19/2010	5.92
11/22/2010	5.86
11/23/2010	5.82
11/24/2010	5.95
11/26/2010	5.86
11/29/2010	5.79
11/30/2010	5.75
12/1/2010	5.89
12/2/2010	5.91
12/3/2010	5.96
12/6/2010	5.89
12/7/2010	6.07
12/8/2010	6.1
12/9/2010	6.03
12/10/2010	6.05
12/13/2010	6.03
12/14/2010	6.18
12/15/2010	6.22
12/16/2010	6.19
12/17/2010	6.01
12/20/2010	6.06
12/21/2010	6.02
12/22/2010	6.04
12/23/2010	6.06
12/27/2010	6.01
12/28/2010	6.13
12/29/2010	6
12/30/2010	6.02
12/31/2010	5.93
1/3/2011	6.01
1/4/2011	6.05

1/5/2011	6.15
1/6/2011	6.09
1/7/2011	6.05
1/10/2011	6.04
1/11/2011	6.03
1/12/2011	6.05
1/13/2011	6.03
1/14/2011	6.06
1/18/2011	6.08
1/19/2011	6.04
1/20/2011	6.14
1/21/2011	6.09
1/24/2011	6.07
1/25/2011	5.98
1/26/2011	6.09
1/27/2011	6.05
1/28/2011	6.01
1/31/2011	6.05
2/1/2011	6.1
2/2/2011	6.12
2/3/2011	6.14
2/4/2011	6.21
2/7/2011	6.17
2/8/2011	6.22
2/9/2011	6.15
2/10/2011	6.21
2/11/2011	6.17
2/14/2011	6.12
2/15/2011	6.1
2/16/2011	6.1
2/17/2011	6.09
2/18/2011	6.13
2/22/2011	6.04
2/23/2011	6.04
2/24/2011	5.99
2/25/2011	5.96
2/28/2011	5.92
3/1/2011	5.93
3/2/2011	5.98
3/3/2011	6.07
3/4/2011	6.03
3/7/2011	6.04

3/8/2011	6.09
3/9/2011	6.02
3/10/2011	5.96
3/11/2011	5.96
3/14/2011	5.94
3/15/2011	5.95
3/16/2011	5.86
3/17/2011	5.9
3/18/2011	5.91
3/21/2011	5.92
3/22/2011	5.92
3/23/2011	5.93
3/24/2011	5.95
3/25/2011	5.98
3/28/2011	5.97
3/29/2011	6.02
3/30/2011	6
3/31/2011	5.99
4/1/2011	5.98
4/4/2011	5.98
4/5/2011	6
4/6/2011	6.07
4/7/2011	6.11
4/8/2011	6.11
4/11/2011	6.11
4/12/2011	6.06
4/13/2011	6.03
4/14/2011	6.02
4/15/2011	5.95
4/18/2011	5.94
4/19/2011	5.91
4/20/2011	5.94
4/21/2011	5.94
4/25/2011	5.93
4/26/2011	5.87
4/27/2011	5.92
4/28/2011	5.89
4/29/2011	5.86
5/2/2011	5.85
5/3/2011	5.82
5/4/2011	5.78
5/5/2011	5.74

5/6/2011	5.75
5/9/2011	5.77
5/10/2011	5.8
5/11/2011	5.76
5/12/2011	5.82
5/13/2011	5.78
5/16/2011	5.72
5/17/2011	5.67
5/18/2011	5.73
5/19/2011	5.74
5/20/2011	5.74
5/23/2011	5.71
5/24/2011	5.7
5/25/2011	5.73
5/26/2011	5.66
5/27/2011	5.67
5/31/2011	5.64
6/1/2011	5.58
6/2/2011	5.68
6/3/2011	5.66
6/6/2011	5.69
6/7/2011	5.69
6/8/2011	5.64
6/9/2011	5.66
6/10/2011	5.62
6/13/2011	5.64
6/14/2011	5.74
6/15/2011	5.63
6/16/2011	5.6
6/17/2011	5.65
6/20/2011	5.65
6/21/2011	5.66
6/22/2011	5.67
6/23/2011	5.6
6/24/2011	5.62
6/27/2011	5.73
6/28/2011	5.77
6/29/2011	5.81
6/30/2011	5.82
7/1/2011	5.84
7/5/2011	5.83
7/6/2011	5.79

7/7/2011	5.81
7/8/2011	5.71
7/11/2011	5.65
7/12/2011	5.63
7/13/2011	5.62
7/14/2011	5.68
7/15/2011	5.68
7/18/2011	5.72
7/19/2011	5.63
7/20/2011	5.7
7/21/2011	5.74
7/22/2011	5.67
7/25/2011	5.73
7/26/2011	5.68
7/27/2011	5.68
7/28/2011	5.66
7/29/2011	5.54
8/1/2011	5.48
8/2/2011	5.34
8/3/2011	5.29
8/4/2011	5.15
8/5/2011	5.25
8/8/2011	5.16
8/9/2011	5.08
8/10/2011	5.06
8/11/2011	5.33
8/12/2011	5.23
8/15/2011	5.29
8/16/2011	5.22
8/17/2011	5.15
8/18/2011	5.05
8/19/2011	5.01
8/22/2011	5.06
8/23/2011	5.17
8/24/2011	5.32
8/25/2011	5.31
8/26/2011	5.26
8/29/2011	5.35
8/30/2011	5.25
8/31/2011	5.33
9/1/2011	5.23
9/2/2011	5.04

9/6/2011	5.01
9/7/2011	5.11
9/8/2011	5.07
9/9/2011	5.04
9/12/2011	5.04
9/13/2011	5.14
9/14/2011	5.16
9/15/2011	5.24
9/16/2011	5.23
9/19/2011	5.13
9/20/2011	5.16
9/21/2011	5
9/22/2011	4.9
9/23/2011	5
9/26/2011	5.13
9/27/2011	5.25
9/28/2011	5.24
9/29/2011	5.15
9/30/2011	5.07
10/3/2011	4.92
10/4/2011	4.93
10/5/2011	5.08
10/6/2011	5.16
10/7/2011	5.23
10/11/2011	5.33
10/12/2011	5.43
10/13/2011	5.35
10/14/2011	5.4
10/17/2011	5.32
10/18/2011	5.3
10/19/2011	5.27
10/20/2011	5.28
10/21/2011	5.33
10/24/2011	5.35
10/25/2011	5.2
10/26/2011	5.25
10/27/2011	5.37
10/28/2011	5.24
10/31/2011	5.08
11/1/2011	4.9
11/2/2011	4.92
11/3/2011	4.99

11/4/2011	4.97
11/7/2011	4.9
11/8/2011	4.99
11/9/2011	4.89
11/10/2011	4.98
11/14/2011	4.96
11/15/2011	4.99
11/16/2011	4.96
11/17/2011	4.88
11/18/2011	4.92
11/21/2011	4.88
11/22/2011	4.87
11/23/2011	4.8
11/25/2011	4.9
11/28/2011	4.91
11/29/2011	4.96
11/30/2011	5.07
12/1/2011	5.17
12/2/2011	5.09
12/5/2011	5.11
12/6/2011	5.17
12/7/2011	5.1
12/8/2011	5.08
12/9/2011	5.17
12/12/2011	5.12
12/13/2011	5.07
12/14/2011	4.98
12/15/2011	5
12/16/2011	4.93
12/19/2011	4.9
12/20/2011	5.03
12/21/2011	5.11
12/22/2011	5.09
12/23/2011	5.18
12/27/2011	5.15
12/28/2011	5.01
12/29/2011	5.02
12/30/2011	4.99
1/3/2012	5.1
1/4/2012	5.15
1/5/2012	5.14
1/6/2012	5.1

1/9/2012	5.12
1/10/2012	5.09
1/11/2012	5.03
1/12/2012	5.03
1/13/2012	4.95
1/17/2012	4.93
1/18/2012	5
1/19/2012	5.04
1/20/2012	5.1
1/23/2012	5.15
1/24/2012	5.16
1/25/2012	5.15
1/26/2012	5.08
1/27/2012	5.04
1/30/2012	4.95
1/31/2012	4.91
2/1/2012	4.97
2/2/2012	4.96
2/3/2012	5.09
2/6/2012	5.01
2/7/2012	5.06
2/8/2012	5.05
2/9/2012	5.08
2/10/2012	5
2/13/2012	5.05
2/14/2012	4.97
2/15/2012	5
2/16/2012	5.05
2/17/2012	5.07
2/21/2012	5.1
2/22/2012	5.06
2/23/2012	5.03
2/24/2012	5
2/27/2012	4.94
2/28/2012	4.96
2/29/2012	4.98
3/1/2012	5.05
3/2/2012	5.01
3/5/2012	5.03
3/6/2012	4.95
3/7/2012	4.98
3/8/2012	5.03

3/9/2012	5.04
3/12/2012	5.02
3/13/2012	5.11
3/14/2012	5.25
3/15/2012	5.25
3/16/2012	5.25
3/19/2012	5.32
3/20/2012	5.29
3/21/2012	5.21
3/22/2012	5.2
3/23/2012	5.15
3/26/2012	5.16
3/27/2012	5.13
3/28/2012	5.13
3/29/2012	5.1
3/30/2012	5.2
4/2/2012	5.22
4/3/2012	5.29
4/4/2012	5.26
4/5/2012	5.2
4/6/2012	5.13
4/9/2012	5.1
4/10/2012	5.07
4/11/2012	5.12
4/12/2012	5.14
4/13/2012	5.08
4/16/2012	5.05
4/17/2012	5.09
4/18/2012	5.07
4/19/2012	5.05
4/20/2012	5.07
4/23/2012	5.03
4/24/2012	5.07
4/25/2012	5.09
4/26/2012	5.08
4/27/2012	5.06
4/30/2012	5.06
5/1/2012	5.11
5/2/2012	5.07
5/3/2012	5.07
5/4/2012	5.03
5/7/2012	5.02

5/8/2012	4.98
5/9/2012	5
5/10/2012	5.01
5/11/2012	4.96
5/14/2012	4.9
5/15/2012	4.89
5/16/2012	4.9
5/17/2012	4.81
5/18/2012	4.85
5/21/2012	4.86
5/22/2012	5.02
5/23/2012	4.94
5/24/2012	5.02
5/25/2012	5.02
5/29/2012	5.01
5/30/2012	4.9
5/31/2012	4.87
6/1/2012	4.75
6/4/2012	4.78
6/5/2012	4.83
6/6/2012	4.94
6/7/2012	4.96
6/8/2012	4.97
6/11/2012	4.94
6/12/2012	4.98
6/13/2012	4.92
6/14/2012	4.92
6/15/2012	4.9
6/18/2012	4.9
6/19/2012	4.94
6/20/2012	4.93
6/21/2012	4.89
6/22/2012	4.96
6/25/2012	4.89
6/26/2012	4.91
6/27/2012	4.91
6/28/2012	4.88
6/29/2012	4.99

Institution Name	Ticker	Period Ended (mm/dd/yyyy)	Total Assets (Reported) *($000)*	Energy Operating Revenue (Reported) *($000)*	Reported Net Operating Income (Reported) *($000)*
AGL Resources Inc.	GAS	12/31/2011	13,913,000	2,338,000	440,000
Atmos Energy Corporation	ATO	9/30/2011	7,282,871	4,347,634	441,899
Laclede Group, Inc. (The)	LG	9/30/2011	1,783,082	1,603,307	118,247
New Jersey Resources Corporation	NJR	9/30/2011	2,649,444	3,009,209	143,001
Northwest Natural Gas Company	NWN	12/31/2011	2,746,574	848,796	144,845
Piedmont Natural Gas Company, Inc.	PNY	10/31/2011	3,242,541	1,433,905	143,011
South Jersey Industries, Inc.	SJI	12/31/2011	2,247,510	828,560	121,607
Southwest Gas Corporation	SWX	12/31/2011	4,276,007	1,887,188	250,080
MDU Resources Group, Inc.	MDU	12/31/2011	6,556,125	4,050,492	406,367

Source: SNL Financial

	GAS				ATO				LG				NJR		
	Low	High			Low	High			Low	High			Low	High	
Jan-12	40.64	42.88		Jan-12	31.94	33.83		Jan-12	39.91	41.93		Jan-12	46.82	50.28	
Feb-12	39.44	42.00		Feb-12	30.68	33.05		Feb-12	40.67	43.00		Feb-12	46.63	49.66	
Mar-12	38.42	40.14		Mar-12	30.39	31.60		Mar-12	38.58	41.46		Mar-12	43.86	47.03	
Apr-12	37.75	39.75		Apr-12	30.80	32.65		Apr-12	38.45	39.98		Apr-12	42.06	45.50	
May-12	36.59	40.29		May-12	32.10	33.93		May-12	37.70	40.39		May-12	41.47	44.38	
Jun-12	36.72	39.32		Jun-12	32.52	35.77		Jun-12	36.53	39.86		Jun-12	41.11	44.37	
	38.26	40.73	39.50		31.41	33.47	32.44		38.64	41.10	39.87		43.66	46.87	45.26

GAS			ATO			LG			NJR		
Date	Low	High	Date	Low	High	Date	Low	High	Date	Low	High
1/3/2012	41.88	42.88	1/3/2012	33.06	33.83	1/3/2012	40.45	41.18	1/3/2012	49.08	50.28
1/4/2012	41.60	42.17	1/4/2012	32.98	33.48	1/4/2012	40.37	41.02	1/4/2012	49.19	49.76
1/5/2012	41.17	41.89	1/5/2012	32.47	33.01	1/5/2012	40.18	40.82	1/5/2012	48.69	49.12
1/6/2012	41.13	41.95	1/6/2012	32.63	32.95	1/6/2012	40.25	40.69	1/6/2012	48.73	49.38
1/9/2012	40.80	41.35	1/9/2012	32.27	32.83	1/9/2012	40.00	40.40	1/9/2012	48.67	49.45
1/10/2012	41.01	41.50	1/10/2012	32.25	32.60	1/10/2012	40.22	40.50	1/10/2012	48.86	49.50
1/11/2012	41.01	41.38	1/11/2012	32.16	32.56	1/11/2012	40.11	40.44	1/11/2012	48.34	48.71
1/12/2012	40.98	41.42	1/12/2012	32.27	32.61	1/12/2012	40.01	40.34	1/12/2012	48.09	48.76
1/13/2012	40.64	41.30	1/13/2012	32.05	32.56	1/13/2012	39.91	40.26	1/13/2012	47.35	48.32
1/17/2012	41.37	41.94	1/17/2012	32.14	32.70	1/17/2012	40.20	40.50	1/17/2012	47.90	48.42
1/18/2012	41.25	41.87	1/18/2012	32.17	32.49	1/18/2012	40.01	40.41	1/18/2012	47.69	48.17
1/19/2012	41.26	41.92	1/19/2012	32.07	32.58	1/19/2012	40.15	40.46	1/19/2012	47.53	48.25
1/20/2012	41.35	42.05	1/20/2012	32.15	32.66	1/20/2012	40.06	40.60	1/20/2012	47.52	47.89
1/23/2012	41.61	42.24	1/23/2012	32.44	32.93	1/23/2012	40.26	40.82	1/23/2012	47.61	48.26
1/24/2012	41.23	41.79	1/24/2012	32.15	32.54	1/24/2012	40.19	40.79	1/24/2012	47.35	48.04
1/25/2012	41.00	42.02	1/25/2012	31.94	32.64	1/25/2012	40.29	41.00	1/25/2012	47.19	48.21
1/26/2012	41.68	42.28	1/26/2012	32.58	33.04	1/26/2012	40.73	41.91	1/26/2012	48.34	48.95
1/27/2012	41.47	42.34	1/27/2012	32.29	32.97	1/27/2012	40.88	41.93	1/27/2012	47.68	48.86
1/30/2012	41.22	41.62	1/30/2012	32.07	32.32	1/30/2012	41.31	41.79	1/30/2012	46.82	47.72
1/31/2012	41.10	41.58	1/31/2012	32.07	32.47	1/31/2012	41.41	41.75	1/31/2012	46.85	47.85
2/1/2012	41.42	41.85	2/1/2012	32.41	32.68	2/1/2012	41.72	42.68	2/1/2012	47.39	48.10
2/2/2012	41.55	41.86	2/2/2012	32.45	32.88	2/2/2012	42.32	42.76	2/2/2012	47.86	48.48
2/3/2012	41.43	42.00	2/3/2012	32.67	33.02	2/3/2012	42.64	43.00	2/3/2012	48.61	49.07
2/6/2012	41.25	41.52	2/6/2012	32.40	32.81	2/6/2012	42.25	42.67	2/6/2012	48.46	48.97
2/7/2012	41.01	41.87	2/7/2012	32.45	33.05	2/7/2012	42.35	42.84	2/7/2012	48.67	49.66
2/8/2012	41.32	41.86	2/8/2012	32.00	32.77	2/8/2012	42.30	42.78	2/8/2012	48.12	49.34
2/9/2012	41.56	41.90	2/9/2012	32.00	32.66	2/9/2012	42.20	42.62	2/9/2012	48.17	49.05

2/10/2012	41.18	41.56	2/10/2012	31.51	32.05	2/10/2012	41.86	42.30	2/10/2012	47.07	48.04
2/13/2012	41.20	41.91	2/13/2012	31.51	32.15	2/13/2012	41.93	42.33	2/13/2012	47.27	47.99
2/14/2012	40.83	41.38	2/14/2012	31.43	31.88	2/14/2012	41.62	42.00	2/14/2012	47.04	47.72
2/15/2012	40.62	41.23	2/15/2012	31.28	31.73	2/15/2012	41.26	42.00	2/15/2012	46.81	47.65
2/16/2012	40.87	41.32	2/16/2012	31.41	31.98	2/16/2012	41.49	42.20	2/16/2012	46.92	48.46
2/17/2012	41.15	41.42	2/17/2012	31.50	32.08	2/17/2012	41.88	42.19	2/17/2012	47.55	48.45
2/21/2012	41.06	41.74	2/21/2012	31.71	32.16	2/21/2012	41.64	42.31	2/21/2012	47.45	48.10
2/22/2012	40.00	41.49	2/22/2012	31.78	32.23	2/22/2012	41.63	42.10	2/22/2012	47.05	47.77
2/23/2012	40.79	41.48	2/23/2012	31.68	32.11	2/23/2012	41.78	42.24	2/23/2012	47.17	47.83
2/24/2012	40.27	41.43	2/24/2012	31.68	32.01	2/24/2012	41.76	42.21	2/24/2012	47.55	48.13
2/27/2012	39.96	40.46	2/27/2012	31.22	31.65	2/27/2012	41.51	42.04	2/27/2012	46.90	47.55
2/28/2012	39.50	40.46	2/28/2012	30.72	31.46	2/28/2012	40.67	42.28	2/28/2012	46.63	47.26
2/29/2012	39.44	40.09	2/29/2012	30.68	31.23	2/29/2012	40.83	41.83	2/29/2012	46.64	47.29
3/1/2012	39.54	40.06	3/1/2012	30.71	31.09	3/1/2012	40.70	41.46	3/1/2012	46.30	47.03
3/2/2012	39.15	39.62	3/2/2012	30.76	31.06	3/2/2012	40.19	40.91	3/2/2012	45.72	46.34
3/5/2012	39.17	39.81	3/5/2012	30.71	31.23	3/5/2012	40.10	41.35	3/5/2012	45.61	46.38
3/6/2012	39.22	39.61	3/6/2012	30.65	31.07	3/6/2012	40.68	41.19	3/6/2012	45.65	46.17
3/7/2012	39.23	39.78	3/7/2012	30.52	30.90	3/7/2012	40.60	40.98	3/7/2012	45.35	45.89
3/8/2012	39.10	39.56	3/8/2012	30.57	31.06	3/8/2012	40.06	40.71	3/8/2012	45.31	45.94
3/9/2012	39.01	39.49	3/9/2012	30.89	31.28	3/9/2012	40.43	41.23	3/9/2012	45.46	46.36
3/12/2012	39.38	39.65	3/12/2012	31.11	31.35	3/12/2012	40.86	41.20	3/12/2012	45.43	45.90
3/13/2012	39.62	40.08	3/13/2012	31.15	31.46	3/13/2012	40.84	41.31	3/13/2012	44.87	45.61
3/14/2012	39.65	40.14	3/14/2012	31.05	31.53	3/14/2012	40.22	41.24	3/14/2012	44.52	45.44
3/15/2012	39.09	39.76	3/15/2012	30.73	31.16	3/15/2012	39.79	40.47	3/15/2012	44.24	44.92
3/16/2012	39.06	39.68	3/16/2012	30.66	30.90	3/16/2012	39.67	40.27	3/16/2012	44.34	44.77
3/19/2012	38.68	39.21	3/19/2012	30.58	31.04	3/19/2012	39.60	40.14	3/19/2012	44.29	45.00
3/20/2012	38.42	39.18	3/20/2012	30.56	30.90	3/20/2012	39.39	39.93	3/20/2012	44.17	44.67
3/21/2012	38.80	39.23	3/21/2012	30.42	30.73	3/21/2012	39.00	39.67	3/21/2012	44.11	44.58
3/22/2012	38.45	38.94	3/22/2012	30.39	30.62	3/22/2012	38.58	38.91	3/22/2012	43.86	44.28
3/23/2012	38.49	38.86	3/23/2012	30.44	30.80	3/23/2012	38.58	39.04	3/23/2012	44.12	44.66
3/26/2012	38.75	39.19	3/26/2012	30.88	31.19	3/26/2012	39.14	39.54	3/26/2012	44.61	45.40
3/27/2012	38.93	39.35	3/27/2012	30.87	31.21	3/27/2012	39.04	39.31	3/27/2012	45.01	45.30
3/28/2012	38.68	39.25	3/28/2012	30.74	31.20	3/28/2012	38.72	39.11	3/28/2012	44.36	45.06
3/29/2012	38.44	38.98	3/29/2012	30.53	31.22	3/29/2012	38.73	39.10	3/29/2012	44.28	44.75
3/30/2012	38.80	39.24	3/30/2012	31.14	31.60	3/30/2012	38.96	39.30	3/30/2012	44.52	45.05
4/2/2012	39.01	39.75	4/2/2012	31.28	31.95	4/2/2012	38.74	39.63	4/2/2012	44.36	45.26
4/3/2012	39.07	39.49	4/3/2012	31.45	31.82	4/3/2012	39.52	39.94	4/3/2012	44.97	45.50
4/4/2012	39.03	39.24	4/4/2012	31.41	31.75	4/4/2012	39.17	39.78	4/4/2012	44.03	44.87
4/5/2012	38.65	39.10	4/5/2012	31.27	31.76	4/5/2012	39.00	39.37	4/5/2012	43.45	44.07

4/9/2012	38.32	38.53	4/9/2012	30.95	31.26	4/9/2012	38.50	38.86	4/9/2012	42.94	43.35
4/10/2012	37.75	38.24	4/10/2012	30.80	31.17	4/10/2012	38.45	38.87	4/10/2012	42.14	43.07
4/11/2012	37.90	38.51	4/11/2012	30.86	31.24	4/11/2012	38.53	38.90	4/11/2012	42.11	42.75
4/12/2012	37.82	38.32	4/12/2012	30.82	31.17	4/12/2012	38.53	39.01	4/12/2012	42.12	42.78
4/13/2012	37.84	38.44	4/13/2012	30.90	31.37	4/13/2012	38.57	38.94	4/13/2012	42.21	42.89
4/16/2012	37.87	38.19	4/16/2012	30.90	31.56	4/16/2012	38.65	39.38	4/16/2012	42.34	42.91
4/17/2012	38.06	38.53	4/17/2012	31.31	31.87	4/17/2012	39.13	39.57	4/17/2012	42.68	43.22
4/18/2012	37.97	38.46	4/18/2012	31.31	31.71	4/18/2012	38.66	39.19	4/18/2012	42.09	42.89
4/19/2012	37.75	38.19	4/19/2012	31.09	31.54	4/19/2012	38.50	38.89	4/19/2012	42.06	42.78
4/20/2012	37.97	38.33	4/20/2012	31.65	32.12	4/20/2012	38.91	39.38	4/20/2012	42.83	44.15
4/23/2012	37.75	38.03	4/23/2012	31.56	31.85	4/23/2012	38.55	38.85	4/23/2012	42.55	43.00
4/24/2012	37.95	38.36	4/24/2012	31.63	32.00	4/24/2012	38.73	39.49	4/24/2012	42.66	43.08
4/25/2012	38.38	39.02	4/25/2012	32.05	32.31	4/25/2012	39.54	39.98	4/25/2012	42.93	43.36
4/26/2012	38.49	39.00	4/26/2012	32.10	32.36	4/26/2012	39.35	39.62	4/26/2012	42.79	43.08
4/27/2012	38.86	39.28	4/27/2012	32.10	32.47	4/27/2012	38.95	39.64	4/27/2012	42.82	43.21
4/30/2012	39.02	39.48	4/30/2012	32.32	32.65	4/30/2012	39.20	39.69	4/30/2012	42.85	43.34
5/1/2012	38.64	39.56	5/1/2012	32.59	33.15	5/1/2012	39.35	40.39	5/1/2012	43.03	43.91
5/2/2012	38.78	40.29	5/2/2012	32.32	32.89	5/2/2012	39.03	39.47	5/2/2012	42.76	43.23
5/3/2012	38.41	38.80	5/3/2012	32.34	32.96	5/3/2012	39.00	39.46	5/3/2012	42.75	43.56
5/4/2012	38.40	38.84	5/4/2012	32.22	32.70	5/4/2012	38.93	39.38	5/4/2012	42.79	43.55
5/7/2012	38.21	38.69	5/7/2012	32.10	32.49	5/7/2012	38.81	39.35	5/7/2012	42.65	43.31
5/8/2012	38.08	38.61	5/8/2012	32.17	32.71	5/8/2012	38.91	39.30	5/8/2012	42.94	43.84
5/9/2012	38.08	38.53	5/9/2012	32.36	33.20	5/9/2012	38.73	39.16	5/9/2012	43.07	43.65
5/10/2012	38.41	38.93	5/10/2012	32.70	33.02	5/10/2012	38.74	39.28	5/10/2012	43.45	44.12
5/11/2012	38.44	38.97	5/11/2012	32.62	33.15	5/11/2012	38.70	39.05	5/11/2012	43.42	44.05
5/14/2012	38.10	38.49	5/14/2012	32.24	32.77	5/14/2012	38.52	38.97	5/14/2012	42.82	43.34
5/15/2012	37.75	38.27	5/15/2012	32.57	33.07	5/15/2012	38.66	39.00	5/15/2012	42.92	44.19
5/16/2012	37.50	37.83	5/16/2012	32.64	32.95	5/16/2012	38.76	39.09	5/16/2012	43.63	44.14
5/17/2012	36.94	37.83	5/17/2012	33.10	33.93	5/17/2012	38.53	39.00	5/17/2012	43.49	44.38
5/18/2012	36.69	37.25	5/18/2012	32.61	33.30	5/18/2012	38.41	38.93	5/18/2012	42.82	43.79
5/21/2012	36.59	36.95	5/21/2012	32.32	32.80	5/21/2012	38.00	38.52	5/21/2012	42.55	43.00
5/22/2012	36.88	37.22	5/22/2012	32.74	33.15	5/22/2012	38.04	38.52	5/22/2012	42.32	42.81
5/23/2012	36.74	37.17	5/23/2012	32.20	32.71	5/23/2012	37.80	39.00	5/23/2012	41.47	42.47
5/24/2012	36.81	37.35	5/24/2012	32.30	32.91	5/24/2012	37.78	38.29	5/24/2012	41.68	42.63
5/25/2012	36.81	37.47	5/25/2012	32.57	32.94	5/25/2012	38.03	38.32	5/25/2012	42.45	42.76
5/29/2012	37.30	37.72	5/29/2012	32.68	33.00	5/29/2012	37.80	38.34	5/29/2012	42.41	42.87
5/30/2012	37.01	37.81	5/30/2012	32.44	32.91	5/30/2012	37.73	38.32	5/30/2012	41.79	42.51
5/31/2012	37.11	37.78	5/31/2012	32.54	33.30	5/31/2012	37.70	38.29	5/31/2012	41.76	42.30
6/1/2012	36.86	37.48	6/1/2012	32.52	33.23	6/1/2012	36.53	37.95	6/1/2012	41.20	41.99

6/4/2012	36.72	37.18	6/4/2012	32.92	33.23	6/4/2012	37.32	38.09	6/4/2012	41.37	41.85
6/5/2012	36.76	37.21	6/5/2012	33.01	33.38	6/5/2012	37.36	37.66	6/5/2012	41.11	42.05
6/6/2012	37.06	37.73	6/6/2012	33.28	33.85	6/6/2012	37.36	38.16	6/6/2012	41.76	42.82
6/7/2012	37.82	38.43	6/7/2012	33.70	34.05	6/7/2012	37.61	38.04	6/7/2012	42.70	43.25
6/8/2012	37.66	38.17	6/8/2012	33.48	33.99	6/8/2012	37.63	38.43	6/8/2012	42.12	43.77
6/11/2012	38.00	38.50	6/11/2012	33.77	34.23	6/11/2012	38.45	38.96	6/11/2012	43.15	43.92
6/12/2012	37.71	38.16	6/12/2012	33.61	34.00	6/12/2012	38.31	38.75	6/12/2012	42.93	43.79
6/13/2012	37.88	38.36	6/13/2012	33.70	34.11	6/13/2012	38.48	38.95	6/13/2012	42.81	43.71
6/14/2012	38.11	38.56	6/14/2012	34.01	34.37	6/14/2012	38.61	38.93	6/14/2012	43.07	43.54
6/15/2012	38.47	38.79	6/15/2012	34.26	34.64	6/15/2012	38.93	39.50	6/15/2012	43.40	44.37
6/18/2012	38.48	38.80	6/18/2012	34.13	34.64	6/18/2012	39.08	39.59	6/18/2012	43.59	44.02
6/19/2012	38.59	39.32	6/19/2012	34.38	34.76	6/19/2012	39.27	39.86	6/19/2012	43.71	44.10
6/20/2012	38.70	39.22	6/20/2012	33.96	34.50	6/20/2012	38.98	39.62	6/20/2012	43.17	43.79
6/21/2012	37.63	39.06	6/21/2012	33.74	34.30	6/21/2012	38.55	39.17	6/21/2012	42.45	43.22
6/22/2012	37.58	38.28	6/22/2012	33.82	34.11	6/22/2012	38.69	39.05	6/22/2012	42.33	42.71
6/25/2012	37.59	38.14	6/25/2012	33.49	33.81	6/25/2012	38.50	38.82	6/25/2012	41.94	42.52
6/26/2012	37.83	38.24	6/26/2012	33.57	33.86	6/26/2012	38.42	38.78	6/26/2012	41.78	42.46
6/27/2012	37.89	38.29	6/27/2012	33.73	34.35	6/27/2012	38.50	39.27	6/27/2012	41.75	43.05
6/28/2012	37.82	38.50	6/28/2012	34.07	34.86	6/28/2012	38.67	39.25	6/28/2012	42.43	43.08
6/29/2012	38.46	39.12	6/29/2012	34.69	35.77	6/29/2012	39.45	39.81	6/29/2012	43.22	43.71

Source: Bloomberg Professional

	NWN				PNY				SJI				SWX		
	Low	High			Low	High			Low	High			Low	High	
Jan-12	46.60	48.83		Jan-12	32.38	34.63		Jan-12	54.09	57.99		Jan-12	40.51	43.22	
Feb-12	45.74	49.49		Feb-12	32.25	34.00		Feb-12	51.91	56.15		Feb-12	41.50	42.98	
Mar-12	44.40	46.52		Mar-12	30.70	32.96		Mar-12	49.55	52.06		Mar-12	41.89	43.64	
Apr-12	43.90	46.08		Apr-12	29.05	31.61		Apr-12	47.42	51.03		Apr-12	40.76	43.52	
May-12	44.87	46.66		May-12	28.90	30.71		May-12	46.52	49.84		May-12	41.03	43.42	
Jun-12	45.50	48.56		Jun-12	29.71	33.03		Jun-12	47.46	51.90		Jun-12	39.46	44.64	
	45.17	47.69	46.43		30.50	32.82	31.66		49.49	53.16	51.33		40.86	43.57	42.21

NWN			PNY			SJI			SWX		
Date	Low	High	Date	Low	High	Date	Low	High	Date	Low	High
1/3/2012	47.47	48.83	1/3/2012	34.00	34.63	1/3/2012	56.61	57.99	1/3/2012	42.44	43.22
1/4/2012	47.55	48.15	1/4/2012	33.77	34.14	1/4/2012	56.58	57.00	1/4/2012	42.06	42.73
1/5/2012	46.91	47.89	1/5/2012	33.18	33.71	1/5/2012	55.95	57.00	1/5/2012	41.65	42.46
1/6/2012	47.11	47.77	1/6/2012	33.16	33.68	1/6/2012	55.97	56.80	1/6/2012	41.90	42.32
1/9/2012	46.83	47.57	1/9/2012	33.06	33.51	1/9/2012	55.39	56.35	1/9/2012	41.51	42.07
1/10/2012	47.13	47.58	1/10/2012	33.34	33.85	1/10/2012	55.94	56.43	1/10/2012	41.43	42.10
1/11/2012	47.05	47.55	1/11/2012	33.23	33.46	1/11/2012	55.72	56.10	1/11/2012	41.03	41.59
1/12/2012	47.01	47.52	1/12/2012	33.00	33.41	1/12/2012	55.30	55.91	1/12/2012	40.92	41.40
1/13/2012	46.74	47.17	1/13/2012	32.64	33.07	1/13/2012	54.92	55.49	1/13/2012	40.51	40.89
1/17/2012	47.04	47.69	1/17/2012	33.01	33.46	1/17/2012	55.44	56.01	1/17/2012	40.76	41.62
1/18/2012	46.68	47.25	1/18/2012	32.67	33.10	1/18/2012	54.84	55.53	1/18/2012	41.07	41.75
1/19/2012	46.87	47.25	1/19/2012	32.54	32.94	1/19/2012	54.19	55.08	1/19/2012	41.32	41.81
1/20/2012	46.79	47.36	1/20/2012	32.52	32.79	1/20/2012	54.49	54.88	1/20/2012	41.18	41.73
1/23/2012	46.96	47.37	1/23/2012	32.57	33.00	1/23/2012	54.67	55.40	1/23/2012	41.53	42.17
1/24/2012	46.82	47.20	1/24/2012	32.52	32.80	1/24/2012	54.55	54.92	1/24/2012	41.34	41.63
1/25/2012	46.60	47.39	1/25/2012	32.38	32.99	1/25/2012	54.27	54.84	1/25/2012	41.17	42.17
1/26/2012	47.36	48.46	1/26/2012	33.01	33.52	1/26/2012	54.55	55.32	1/26/2012	42.01	42.49
1/27/2012	47.38	47.99	1/27/2012	32.95	33.45	1/27/2012	54.73	55.34	1/27/2012	42.00	42.49
1/30/2012	46.97	47.54	1/30/2012	32.65	33.04	1/30/2012	54.09	54.65	1/30/2012	41.67	42.02
1/31/2012	47.18	47.71	1/31/2012	32.65	33.16	1/31/2012	54.10	55.08	1/31/2012	41.52	42.24
2/1/2012	47.57	48.55	2/1/2012	33.00	33.48	2/1/2012	54.68	55.21	2/1/2012	41.83	42.50
2/2/2012	48.32	48.75	2/2/2012	33.41	33.71	2/2/2012	54.68	55.17	2/2/2012	42.17	42.60
2/3/2012	48.80	49.49	2/3/2012	33.73	33.95	2/3/2012	55.56	56.15	2/3/2012	42.50	42.87
2/6/2012	48.88	49.29	2/6/2012	33.52	33.88	2/6/2012	55.16	55.68	2/6/2012	42.27	42.73
2/7/2012	48.71	49.37	2/7/2012	33.45	34.00	2/7/2012	55.10	55.74	2/7/2012	42.37	42.86
2/8/2012	48.37	48.99	2/8/2012	33.46	33.92	2/8/2012	54.73	55.63	2/8/2012	42.18	42.87
2/9/2012	48.14	48.83	2/9/2012	33.41	33.96	2/9/2012	54.78	55.35	2/9/2012	42.31	42.91

2/10/2012	47.69	48.14	2/10/2012	33.13	33.45	2/10/2012	54.00	54.65	2/10/2012	41.92	42.73
2/13/2012	47.89	48.28	2/13/2012	33.21	33.58	2/13/2012	54.08	54.68	2/13/2012	41.81	42.38
2/14/2012	47.31	48.03	2/14/2012	33.06	33.50	2/14/2012	53.89	54.42	2/14/2012	41.50	42.05
2/15/2012	47.22	47.99	2/15/2012	32.79	33.49	2/15/2012	53.47	54.50	2/15/2012	41.69	42.21
2/16/2012	47.52	48.41	2/16/2012	32.92	33.69	2/16/2012	53.58	54.78	2/16/2012	41.86	42.84
2/17/2012	48.15	48.69	2/17/2012	33.63	33.99	2/17/2012	54.54	55.16	2/17/2012	42.38	42.98
2/21/2012	47.96	48.63	2/21/2012	33.55	33.99	2/21/2012	54.25	54.84	2/21/2012	42.32	42.89
2/22/2012	47.80	48.46	2/22/2012	33.35	33.78	2/22/2012	54.02	54.52	2/22/2012	42.19	42.68
2/23/2012	48.04	48.72	2/23/2012	33.43	33.86	2/23/2012	54.11	54.72	2/23/2012	42.43	42.98
2/24/2012	48.04	48.68	2/24/2012	33.23	33.89	2/24/2012	54.14	54.78	2/24/2012	42.35	42.90
2/27/2012	47.60	48.14	2/27/2012	32.72	33.24	2/27/2012	53.71	54.49	2/27/2012	41.81	42.71
2/28/2012	46.13	47.80	2/28/2012	32.25	32.95	2/28/2012	52.41	53.90	2/28/2012	41.75	42.62
2/29/2012	45.74	47.05	2/29/2012	32.25	32.72	2/29/2012	51.91	54.40	2/29/2012	42.26	42.93
3/1/2012	45.28	46.31	3/1/2012	31.89	32.60	3/1/2012	50.76	51.95	3/1/2012	42.32	42.93
3/2/2012	45.14	45.82	3/2/2012	31.38	32.21	3/2/2012	50.49	51.74	3/2/2012	42.29	42.82
3/5/2012	45.00	46.11	3/5/2012	31.43	32.59	3/5/2012	50.54	51.94	3/5/2012	42.25	43.12
3/6/2012	45.22	45.78	3/6/2012	32.03	32.46	3/6/2012	51.27	51.83	3/6/2012	42.33	42.94
3/7/2012	45.18	45.93	3/7/2012	31.98	32.49	3/7/2012	50.74	51.36	3/7/2012	42.26	42.75
3/8/2012	45.29	45.79	3/8/2012	32.13	32.53	3/8/2012	50.79	51.44	3/8/2012	42.50	42.98
3/9/2012	45.48	46.32	3/9/2012	32.16	32.96	3/9/2012	51.13	52.00	3/9/2012	42.75	43.38
3/12/2012	45.77	46.33	3/12/2012	31.96	32.47	3/12/2012	51.36	52.00	3/12/2012	43.09	43.44
3/13/2012	45.96	46.43	3/13/2012	32.10	32.49	3/13/2012	51.37	52.06	3/13/2012	43.02	43.62
3/14/2012	45.81	46.52	3/14/2012	31.72	32.45	3/14/2012	51.05	51.97	3/14/2012	42.88	43.64
3/15/2012	45.29	46.02	3/15/2012	31.23	31.82	3/15/2012	50.44	51.13	3/15/2012	42.47	43.08
3/16/2012	45.26	45.79	3/16/2012	31.52	31.92	3/16/2012	50.84	51.19	3/16/2012	42.85	43.22
3/19/2012	45.12	45.68	3/19/2012	31.35	31.81	3/19/2012	50.51	51.18	3/19/2012	42.44	43.25
3/20/2012	44.87	45.42	3/20/2012	31.41	31.67	3/20/2012	50.54	51.10	3/20/2012	42.53	42.86
3/21/2012	44.72	45.18	3/21/2012	31.01	31.43	3/21/2012	50.46	50.97	3/21/2012	42.40	42.67
3/22/2012	44.40	44.89	3/22/2012	30.75	31.05	3/22/2012	50.00	50.72	3/22/2012	41.89	42.40
3/23/2012	44.66	45.25	3/23/2012	30.93	31.24	3/23/2012	50.19	50.78	3/23/2012	42.02	42.45
3/26/2012	45.32	45.73	3/26/2012	31.29	31.63	3/26/2012	50.95	51.48	3/26/2012	42.64	43.21
3/27/2012	45.40	45.72	3/27/2012	31.28	31.57	3/27/2012	50.72	51.24	3/27/2012	42.84	43.11
3/28/2012	45.01	45.67	3/28/2012	30.89	31.35	3/28/2012	49.84	50.90	3/28/2012	42.29	43.00
3/29/2012	44.87	45.45	3/29/2012	30.70	31.10	3/29/2012	49.55	50.25	3/29/2012	42.22	42.85
3/30/2012	45.38	45.69	3/30/2012	31.01	31.26	3/30/2012	50.03	50.40	3/30/2012	42.64	43.01
4/2/2012	45.02	45.93	4/2/2012	30.76	31.55	4/2/2012	49.73	50.70	4/2/2012	42.56	43.33
4/3/2012	45.40	46.08	4/3/2012	31.14	31.61	4/3/2012	50.11	51.03	4/3/2012	42.92	43.52
4/4/2012	45.34	45.82	4/4/2012	30.89	31.17	4/4/2012	49.36	50.00	4/4/2012	42.59	42.98
4/5/2012	45.00	45.54	4/5/2012	30.58	31.09	4/5/2012	48.59	49.54	4/5/2012	42.30	42.66

4/9/2012	44.59	45.00	4/9/2012	30.24	30.59	4/9/2012	48.25	48.61	4/9/2012	41.92	42.28
4/10/2012	43.90	44.81	4/10/2012	29.59	30.26	4/10/2012	47.57	48.44	4/10/2012	41.43	42.05
4/11/2012	44.23	44.52	4/11/2012	29.50	29.95	4/11/2012	47.55	48.19	4/11/2012	41.29	41.74
4/12/2012	44.27	44.85	4/12/2012	29.41	29.68	4/12/2012	47.69	48.24	4/12/2012	40.88	41.68
4/13/2012	44.06	44.70	4/13/2012	29.30	29.89	4/13/2012	47.59	48.21	4/13/2012	41.12	41.53
4/16/2012	44.16	44.67	4/16/2012	29.25	29.64	4/16/2012	47.42	48.19	4/16/2012	41.05	41.53
4/17/2012	44.62	45.17	4/17/2012	29.66	30.06	4/17/2012	48.10	48.83	4/17/2012	41.49	42.21
4/18/2012	44.30	44.80	4/18/2012	29.50	29.83	4/18/2012	48.27	48.63	4/18/2012	41.27	41.84
4/19/2012	44.00	44.61	4/19/2012	29.05	29.60	4/19/2012	47.58	48.44	4/19/2012	40.76	41.41
4/20/2012	44.43	45.01	4/20/2012	29.59	29.87	4/20/2012	48.23	48.81	4/20/2012	41.38	41.83
4/23/2012	44.01	44.45	4/23/2012	29.23	29.47	4/23/2012	47.48	48.18	4/23/2012	40.84	41.32
4/24/2012	44.21	45.06	4/24/2012	29.38	29.84	4/24/2012	47.75	48.41	4/24/2012	41.14	41.54
4/25/2012	45.16	45.49	4/25/2012	29.84	30.13	4/25/2012	48.45	48.95	4/25/2012	41.67	41.90
4/26/2012	44.61	45.35	4/26/2012	29.77	30.14	4/26/2012	48.54	49.09	4/26/2012	41.60	41.80
4/27/2012	45.16	45.77	4/27/2012	29.96	30.32	4/27/2012	48.72	49.19	4/27/2012	41.62	42.00
4/30/2012	45.46	45.82	4/30/2012	30.12	30.52	4/30/2012	48.74	49.34	4/30/2012	41.65	42.14
5/1/2012	45.49	46.33	5/1/2012	30.00	30.71	5/1/2012	48.94	49.84	5/1/2012	41.76	42.90
5/2/2012	45.16	45.74	5/2/2012	29.69	30.02	5/2/2012	48.34	49.02	5/2/2012	41.52	42.05
5/3/2012	45.24	45.95	5/3/2012	29.53	29.97	5/3/2012	48.21	48.86	5/3/2012	41.56	42.03
5/4/2012	44.87	45.52	5/4/2012	29.33	29.57	5/4/2012	47.84	48.29	5/4/2012	41.43	41.78
5/7/2012	45.01	46.66	5/7/2012	29.05	29.53	5/7/2012	47.17	48.05	5/7/2012	41.03	42.57
5/8/2012	45.85	46.63	5/8/2012	29.24	29.64	5/8/2012	47.03	47.86	5/8/2012	42.13	43.15
5/9/2012	45.88	46.45	5/9/2012	29.23	29.74	5/9/2012	47.23	48.00	5/9/2012	42.26	42.78
5/10/2012	46.09	46.59	5/10/2012	29.63	30.03	5/10/2012	47.79	48.40	5/10/2012	42.76	43.42
5/11/2012	45.84	46.39	5/11/2012	29.65	29.94	5/11/2012	47.73	48.08	5/11/2012	42.48	42.98
5/14/2012	45.37	45.90	5/14/2012	29.42	29.80	5/14/2012	47.20	47.73	5/14/2012	42.05	42.80
5/15/2012	45.69	46.19	5/15/2012	29.46	29.85	5/15/2012	47.11	47.51	5/15/2012	42.23	42.76
5/16/2012	45.76	46.08	5/16/2012	29.66	30.13	5/16/2012	47.50	47.83	5/16/2012	42.30	42.62
5/17/2012	45.55	46.15	5/17/2012	29.46	29.97	5/17/2012	47.45	47.87	5/17/2012	42.05	42.58
5/18/2012	45.35	45.88	5/18/2012	29.37	29.81	5/18/2012	47.25	47.82	5/18/2012	41.68	42.31
5/21/2012	45.56	46.16	5/21/2012	29.16	29.59	5/21/2012	47.22	47.68	5/21/2012	41.47	41.94
5/22/2012	45.65	46.17	5/22/2012	29.38	29.62	5/22/2012	47.23	47.70	5/22/2012	41.80	42.08
5/23/2012	45.31	46.08	5/23/2012	28.90	29.47	5/23/2012	46.52	47.55	5/23/2012	41.25	41.99
5/24/2012	45.55	46.32	5/24/2012	29.09	29.63	5/24/2012	46.76	47.43	5/24/2012	41.45	41.99
5/25/2012	46.05	46.45	5/25/2012	29.50	29.79	5/25/2012	47.25	47.60	5/25/2012	41.65	41.99
5/29/2012	45.88	46.42	5/29/2012	29.50	29.89	5/29/2012	47.42	47.98	5/29/2012	41.62	42.23
5/30/2012	45.92	46.49	5/30/2012	29.54	29.97	5/30/2012	47.49	47.96	5/30/2012	41.57	42.04
5/31/2012	45.92	46.66	5/31/2012	29.70	30.53	5/31/2012	47.54	48.67	5/31/2012	41.67	42.22
6/1/2012	45.50	46.16	6/1/2012	29.71	30.52	6/1/2012	47.46	49.05	6/1/2012	39.46	42.13

6/4/2012	45.67	46.10	6/4/2012	29.86	30.27	6/4/2012	48.62	49.03	6/4/2012	41.69	42.10
6/5/2012	45.71	46.51	6/5/2012	30.40	30.95	6/5/2012	48.65	49.47	6/5/2012	41.76	42.32
6/6/2012	46.35	46.72	6/6/2012	30.63	31.68	6/6/2012	49.31	50.43	6/6/2012	42.25	43.20
6/7/2012	46.63	47.15	6/7/2012	31.31	31.99	6/7/2012	50.04	50.49	6/7/2012	42.97	43.65
6/8/2012	46.51	47.31	6/8/2012	30.91	31.85	6/8/2012	49.92	50.66	6/8/2012	42.91	44.00
6/11/2012	46.88	47.69	6/11/2012	31.58	32.06	6/11/2012	50.14	51.05	6/11/2012	43.67	44.28
6/12/2012	46.52	47.06	6/12/2012	31.47	31.90	6/12/2012	49.79	50.56	6/12/2012	43.42	43.99
6/13/2012	46.75	47.41	6/13/2012	31.68	32.20	6/13/2012	49.91	50.84	6/13/2012	43.74	44.40
6/14/2012	46.89	47.47	6/14/2012	31.93	32.31	6/14/2012	50.25	50.84	6/14/2012	43.89	44.22
6/15/2012	47.19	47.83	6/15/2012	32.00	32.50	6/15/2012	50.63	51.39	6/15/2012	44.09	44.43
6/18/2012	47.21	47.87	6/18/2012	32.10	32.48	6/18/2012	50.49	51.05	6/18/2012	43.78	44.36
6/19/2012	47.22	47.94	6/19/2012	32.16	32.64	6/19/2012	50.48	51.29	6/19/2012	44.07	44.64
6/20/2012	47.23	47.77	6/20/2012	31.80	32.32	6/20/2012	50.02	50.82	6/20/2012	43.94	44.50
6/21/2012	47.34	47.68	6/21/2012	31.45	32.03	6/21/2012	49.70	50.27	6/21/2012	43.41	44.15
6/22/2012	47.60	48.19	6/22/2012	31.62	32.15	6/22/2012	49.72	50.49	6/22/2012	43.55	43.94
6/25/2012	47.62	48.04	6/25/2012	31.71	32.27	6/25/2012	49.78	50.29	6/25/2012	43.17	43.64
6/26/2012	47.69	48.04	6/26/2012	31.99	32.60	6/26/2012	50.03	50.62	6/26/2012	43.19	43.60
6/27/2012	47.88	48.50	6/27/2012	32.48	32.94	6/27/2012	50.39	50.89	6/27/2012	43.53	44.19
6/28/2012	47.40	48.37	6/28/2012	32.09	32.65	6/28/2012	50.01	51.02	6/28/2012	43.29	44.04
6/29/2012	47.30	48.56	6/29/2012	32.05	33.03	6/29/2012	50.72	51.90	6/29/2012	43.56	44.17

	GAS Dividend
Jan-12	1.80
Feb-12	1.80
Mar-12	1.80
Apr-12	1.80
May-12	1.84
Jun-12	1.84
	1.81

	ATO Dividend
Jan-12	1.38
Feb-12	1.38
Mar-12	1.38
Apr-12	1.38
May-12	1.38
Jun-12	1.38
	1.38

	LG Dividend
Jan-12	1.66
Feb-12	1.66
Mar-12	1.66
Apr-12	1.66
May-12	1.66
Jun-12	1.66
	1.66

	NJR Dividend
Jan-12	1.52
Feb-12	1.52
Mar-12	1.52
Apr-12	1.52
May-12	1.52
Jun-12	1.52
	1.52

GAS	
2/16/2011	0.45
5/11/2011	0.45
8/17/2011	0.45
11/16/2011	0.45
5/16/2012	0.46

ATO	
2/23/2011	0.34
5/23/2011	0.34
8/23/2011	0.34
11/22/2011	0.35
2/23/2012	0.35
5/23/2012	0.35

LG	
3/9/2011	0.41
6/8/2011	0.41
9/8/2011	0.41
12/8/2011	0.42
3/8/2012	0.42
6/7/2012	0.42

NJR	
3/11/2011	0.36
6/13/2011	0.36
9/13/2011	0.36
12/13/2011	0.38
3/13/2012	0.38
6/13/2012	0.38

Source: Bloomberg Professional

	NWN Dividend
Jan-12	1.78
Feb-12	1.78
Mar-12	1.78
Apr-12	1.78
May-12	1.78
Jun-12	1.78
	1.78

	PNY Dividend
Jan-12	1.16
Feb-12	1.16
Mar-12	1.20
Apr-12	1.20
May-12	1.20
Jun-12	1.20
	1.19

	SJI Dividend
Jan-12	1.61
Feb-12	1.61
Mar-12	1.61
Apr-12	1.61
May-12	1.61
Jun-12	1.61
	1.61

	SWX Dividend
Jan-12	1.06
Feb-12	1.06
Mar-12	1.06
Apr-12	1.06
May-12	1.18
Jun-12	1.18
	1.10

NWN	
1/27/2011	0.44
4/27/2011	0.44
7/27/2011	0.44
10/27/2011	0.45
1/27/2012	0.45
4/26/2012	0.45
7/27/2012	0.45

PNY	
3/23/2011	0.29
6/22/2011	0.29
9/21/2011	0.29
12/22/2011	0.29
3/21/2012	0.30
6/20/2012	0.30

SJI	
3/8/2011	0.37
6/8/2011	0.37
9/7/2011	0.37
12/7/2011	0.40
3/7/2012	0.40
6/7/2012	0.40
9/6/2012	0.40

SWX	
2/11/2011	0.25
5/12/2011	0.27
8/11/2011	0.27
11/10/2011	0.27
2/13/2012	0.27
5/11/2012	0.30
8/13/2012	0.30